EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 22

DATE: Thursday, May 30, 1991

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Thursday, the 30th day of May, 1991, commencing at 10:00 a.m.

VOLUME 22

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
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MS. G. PATTERSON	Member

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---Upon commencing at 10:02 a.m.

THE CHAIRMAN: As you probably know, next week we will sit Monday, Tuesday, Wednesday, but on Thursday, there is a trip to Darlington and so there will be no sitting here on Thursday, for those who are making their plans.

Mr. Shepherd.

MR. SHEPHERD: Thank you, Mr. Chairman.

RONALD TABOREK,
DAVID BARRIE,
JOHN KENNETH SNELSON,
JUDITH RYAN; Resumed.

CROSS-EXAMINATION BY MR. SHEPHERD (continued):

Q. Let me just deal with a couple of matters of clarification from yesterday afternoon --

THE CHAIRMAN: Mr. Shepherd, could you move your microphone a little closer. I think some people are having a little trouble hearing you.

MR. SHEPHERD: I have a tendency to be a bit of a mumbler.

Q. First, Mr. Barrie, you talked about the locked-in energy problem at Bruce yesterday. And I wonder, as I understand it, you now only have a locked-in energy problem if you have transmission outages, right, especially on the 500 kV line?

MR. BARRIE: A. We expect that to be the

case, yes.

Q. I wonder if you could provide us with the forced outage rate of the Bruce transmission facilities and indeed perhaps you could give us a table of, let's say, the last five years' forced outage rates for 500 kV facilities. Is that something that you can get together?

A. Would you like it for just the Bruce to Milton 500 kV, they are the ones that have only just gone in so we won't have any statistics on that or in general for 500 kV.

Q. It probably would be more useful to have a general 500 kV forced outage rate and if you could break out the Bruce line that would be useful too. I am just trying to get a sense of what the problem now is, if there is one.

A. I think we can get that information.

Q. I would appreciate it. Should we get a number for that?

THE CHAIRMAN: Yes. 142...

MR. BARRIE: Could I just be clear, Mr. Shepherd, so that I get exactly what it is you want.

The line can be out either on a forced outage or on a planned outage. You would like it split?

MR. SHEPHERD: Q. Yes. Perhaps the easiest thing to say is you could do a chart of reliability indices for 500 kV splitting out the Bruce line, couldn't you, for, let's say, the last five years. Is that something that the information is available for?

MR. BARRIE: A. I think it is.

Q. That would be the perfect set of information. Thanks.

MRS. FORMUSA: That is 142.52.

MR. SHEPHERD: Q. And the other thing. Mr. Snelson, we were talking yesterday about heat rates, mainly with Mr. Barrie, but at the end of it we talked about the extent to which heat rates and the variability of heat rates are included in LMSTM, and you indicated that you have some sort of calculation of a figure to put in LMSTM. I wonder if you could give us, tell us how that calculation is made. Perhaps just provide us with the calculation to show us how it was done.

MR. SNELSON: A. We can provide you the derivation of the heat rates that are used in LMSTM. That may entail a little time to dig material out from the files and so on.

Q. There is no rush.

A. So, it is not necessarily a straightforward matter, but it can be done.

Q. I would appreciate that.

And that is .53, Mr. Chairman.

THE CHAIRMAN: 142.53.

MR. SHEPHERD: Yes.

Q. Now, when we left off yesterday afternoon, we were talking about load following by generation types. Do you, Mr. Barrie, or anybody on the panel I guess, do you have any projections over the DSP period of the extent to which you expect demands side management and/or non-utility generation to follow load?

MR. SNELSON: A. There are assumptions that are made that are included in the LMSTM data. And beyond that degree of detail, which you already have, I believe, in answer to interrogatories, I am not aware of any more detailed predictions.

Q. So, it is in your avoided cost calculation methodology, right, which is LMSTM?

A. LMSTM is the system energy production cost model which is used for total system cost simulations and is also used as one of the tools in developing avoided costs.

Q. But it isn't in the models you use to

calculate the overall reliability of the system or reserve margins or things like that?

A. The degree to which these reduce primary load is included in the frequency and duration model. The frequency and duration model has load shapes which I believe are load shapes of primary load. And so, to that extent, they are reduced by demand management and load displacement non-utility generation.

Q. And the primary load numbers, are they set out in the frequency and duration model in the chronological load curve that we saw the other day?

A. The frequency and duration model has a load model that has in it a typical daily load shape for three different day types for 12 months. So, that's weekdays, Saturdays, and Sundays, and a peak load duration curve that is used to scale the load shape up and down according to the load level predicted for that day. So, that is the degree of definition of load that is in there.

Q. Now as I understand it, the daily load curve is calculated from the basic load forecast, right; that is, you are going from the basic data without including any impact of program-driven DSM or for that matter load following NUGs?

A. The load shapes of primary load that are in F&D will have been adjusted to be consistent with the load forecast, and the load forecast is both the forecast of basic load and of primary load, so the load shapes will be adjusted to be consistent with the forecasted primary load.

Q. I guess the thing I don't understand from your answer is - and maybe I'm just being dense, it's early yet - is the impact, the load following impact of demand side management or load following non-utility generation reflected in F&D?

A. It is reflected in F&D to the degree that there is a different reduction in peak load than there is a reduction in average load.

Q. And do you believe that that fully reflects then this impact or is it sort of a short-cut?

A. This is we believe the appropriate degree of detail for determining the impact on system reliability. And then the F&D model, frequency and duration model, is a model which is used for reliability evaluations.

Q. So, you believe then that load following is properly reflected in F&D.

A. We have made an appropriate amount of adjustment I believe.

Q. Now, Mr. Barrie, just continuing on with load following, but I want to deal with it from an operational point of view. If you have load following options that you know about that are fairly predictable, how do you deal with those operationally in your day-to-day dispatching of the system?

MR. BARRIE: A. If we had demand management for instance.

Q. Yes. As the amount of load following demand management changes, for example, does that impact on how you dispatch the system on a practical basis?

A. Operationally that would be -- to us demand management just means that the load curve that has to be met will be altered. It is invisible to us how it happens. So, yes it would be factored in in terms of a change load curve that had to be met.

Q. What about load following NUGs. How would you deal with that operationally?

A. I am having to speak hypothetically because we don't have any at the moment.

Q. You don't have any load following NUGs at the moment?

A. Not to my knowledge.

Nearly all of our NUGs are load

displacement NUGs so we don't see it anyway. So, we would only be talking about NUGs that are selling to us. There is very little of that at all and that which we do have tends to be fairly flat.

So, in any event, if I could just say how we would handle it. It would have to be factored into the generation schedule plan that I talked about in my direct evidence, where we do factor in all sources of generation. So, if we had a source of NUGs that we knew reliably followed the load, then it would be factored into that part of the generation schedule plan.

...

[10:15 a.m.] MR. SNELSON: A. Can we distinguish between load following and dispatchability, because I think they are quite different concepts although related.

Q. In fact, I think that's the whole point of this line of questioning. But please, yes, go ahead.

A. The load following or you are describing a tendency to follow load, dispatchability is something quite different in that dispatchability is the ability of the control centre to make decisions as to when to schedule generation. So, a load following characteristic is not dispatchability, but it may change the amount of dispatching that has to be done on the system.

Q. We talked all through Panel 1 about exogenous factors, and it sounds to me like if you have load following NUGs, for example, because they are not dispatchable in that sense that you are talking about, they are a type of exogenous factor, almost like having a different load shape for the day, isn't that right, that you have to deal with?

MR. BARRIE: A. Yes, the remaining generation has to be the load that's left.

Q. Am I right in assuming that it is

harder to run the system, it's harder to dispatch when you have more exogenous factors to deal with, variations in load, variations in non-controllable generation, things like that?

A. I think it would be another variable that we have to cope with. So, to that extent, yes.

Q. And as your generation system relies more heavily on demand side management, especially program-driven demand side management and non-utility generation, presumably that operational constraint, if you like, making it more difficult to operate, is increased?

A. I think that's fair to say, yes.

MR. SNELSON: A. I think that if these things are totally random, yes. But, if there are natural tendencies for some of the exogenous factors, as you were describing yesterday, to be beneficial, then it wouldn't necessarily make things more difficult. So, for instance, I don't think that we would accept that demand management necessarily makes the dispatching problems of the system worse. As we discussed yesterday, there may be a tendency for the demand management savings to be correlated with load, and to the extent that that tends to reduce variability in the net, load that has to be supplied by our system,

then that would tend to reduce operational problems rather than to increase them.

Q. And that's true of load-following NUGs as well, they are predictable, reasonably predictable?

A. That could be true of load-following NUGs, if we have any, yes.

Q. I would like to turn now to the area of reliability. Just come back right to the very basic principles. As I understand the DSP, the two really driving forces behind Hydro's planning and, indeed, all of your operational decision-making, are cost and reliability. And I understand that there are a lot of other things as well, but those are the main ones, right?

A. I think that you cannot ignore the other factors. The other factors such as environmental acceptability and social acceptability are, to some extent, more important than the other two factors.

Q. I am not trying to catch you out.

A. No, I realize that. But reliability and cost are important, but they are only two of a number of important factors.

Q. Am I right, and we tried to find out whether this was actually true and we couldn't nail it

right down, but am I right, do you know whether, in fact, Ontario Hydro is the single most reliable utility in the world, large utility, say?

A. I have no knowledge of that.

Q. Mr. Barrie, Mr. Taborek, do you know where you stand in the scheme of things in term of reliability?

MR. BARRIE: A. I know of some results of CIGRE which is in the national group which does do comparisons of this nature. I don't think I can quote exactly where we are in the batting order, so to speak. We are towards the upper end. I don't think we are the most reliable, though.

Q. No. You're right up there?

A. But, first of all, let me clarify right away. Nearly all of the numbers that we read off those reliability reports that get assembled under CIGRE, the vast majority of unreliability events being reported are transmission related. And as such, as we pointed out on numerous occasions here, transmission is an issue but it's not what we are essentially talking about when we are talking about generation reserve margins and that kind of thing.

Q. Yes.

DR. CONNELL: Excuse me, what is the

source you are citing, Mr. Barrie?

MR. BARRIE: CIDGRE.

MR. SNELSON: I can tell you what it stands for, it's in French. It's Conference International de Grand Reseaux Electrique, which means, roughly translated, it's the International Conference on Large Electricity Systems.

DR. CONNELL: What came after "Grand"?

MR. SNELSON: Grand Resaux, reasons.

DR. CONNELL: Network.

MR. SNELSON: R-E-S-A-U-X, I think is how it's spelled, but my French is...

DR. CONNELL: R-E-S-E-A-U would be network, or system.

MR. SNELSON: R-E-S-E-A-U-X, I think it is, E-A-U-X. My French spelling isn't as good as my English spelling and my English spelling isn't that good enough either.

So, it's the International Conference on Large Electricity Systems. It's a group that covers a large proportion of Western Europe and North America, Japan. I don't believe that it includes the eastern European countries.

DR. CONNELL: Thank you.

MR. SHEPHERD: Q. Let me come back to

what you just mentioned, that you are concentrating on generation reliabability for the purpose of things like reserve margin, correct?

Do I get a sense, from what you are saying, that in your comparison of generation reliability as between Ontario Hydro and other utilities, you are not as good?

MR. BARRIE: A. I don't know. I don't have that comparison. All I am saying is the comparison of overall reliability experienced by utilities, and that was what my comment was based on.

Q. And on that score Ontario Hydro is really good?

A. Yes.

MR. TABOREK: A. I can perhaps give you some statistics that are one step removed from reliability. I believe I have some actual margins that a number of utilities in Europe have right now, had in '80 and had in '88.

Q. Reserve margins you mean?

A. Yes.

Q. And these are actuals, so they would have to be compared with our actuals. But, for instance, in 1989, Spain had a 32 per cent reserve margin; Norway had 33; Netherlands, 26; Turkey, 46;

Austria, 45; Ireland, 28. I have read about half of them off the table and those are the high ones. And so I would expect, all other things being equal, a higher reserve margin--

Q. Actual reserve margin.

A. --would tend to incline towards better reliability, but all other things aren't equal, of course. But that would be an indication that we probably wouldn't be among the highest.

Q. Of course, that would just speak to generation reliability, right?

A. Yes. And this is a generation hearing, yes.

And I know Japanese, at least one Japanese utility that we have had a chance to speak to would not consider cutting interruptible loads as an energy measure. So, I wouldn't be able to support that we are the most reliable, not with what I know.

Q. All right. When you are dealing with reliability of a particular unit, as I understand your earlier testimony, the key number is forced outage, that's the one that really counts from the point of view of reliabilility?

A. Yes.

Q. And you were talking about the

acronyms DAFOR and DAUFOP. Is that how you say it, DAUFOP.

A. Yes.

Q. Those are the two acronyms that you used to describe forced outage. Force outages don't just include simple breakdowns, right? That's one thing that's included in forced outage, the thing breaks and isn't working. There are other things that are included in forced outages?

A. For example, what do you mean?

Q. Well, for example, if you are on a maintenance outage and you have to extend it, that's a forced outage; isn't it?

MR. SNELSON: A. That is considered to be forced extension of a planned outage, and that is one of the factors accounted for in DAFOR or DAUFOP.

Q. Okay. And so, does that mean, for example, if you planned to spend 18 months on a fuel channel removal and it took 22 months, the first 18 months would be a maintenance outage and the last four months would be DAFOR?

A. The first 18 months would be a planned outage.

Q. Sorry, yes.

A. And any extension would be

considered -- if it was not discretionary, so if it was not the result of a conscious decision to extend it because there was some additional work that needed to be done, and, you know, you could have brought it back into service, if it was not discretionary, it would be considered to be forced and would become part of the DAFOR and DAUFOP.

...

[10:25 a.m.] Q. Well, let me just take that other example then. Let's say, you were doing the fuel channel removal, and you could, in fact, finish it after 18 months, but you find that there is also some problems with the calandria tubes, so you have to fix those, too, and that takes some extra time. Is that a forced outage?

A. If you could have deferred the calandria tube work to another year and you chose to do it this year, it would be planned. If the unit could not have been returned to service because the calandria tubes had some faults in them that needed fixing before they could be returned to service, then that would be considered forced.

Q. Now, there is no consideration of the economic impacts of putting it back in service or not, in terms of whether you are forced to do the work, right? That is, it can be very expensive to put it back in service and then six months later take it out again, to fix the calandria tubes, for example. That expense isn't considered in whether it is forced?

A. That is not considered in whether it is forced, but it is considered in choosing the time to do a planned outage.

Q. Of course. I'm just going to ask you

to look at this supplementary information of 2.14.5 which have provided to you. I couldn't actually find the cover page on 2.14.5, but I don't think it is a problem.

What I'd like you to do is turn to the letter from Mr. Franklin to...

THE CHAIRMAN: I am sorry?

MR. SHEPHARD: It actually looks like a letter from Mrs. Formusa, because that is how I got it.

THE CHAIRMAN: 2.4.15.

MR. SHEPHARD: 2.14.5. It should be next on your pile, Mr. Chairman.

MS. PATTERSON: Dated May 7, 1990.

MR. SHEPHARD: The letter is dated May 7, yes.

THE CHAIRMAN: Go ahead.

MR. SHEPHARD: Q. On the third page of that is a letter to the then Minister of Energy from the president, the then president of Ontario Hydro. And just looking at the description of -- this is a description of the problems you had in December 1989?

MR. BARRIE: A. Yes.

Q. Is that correct?

Just looking at that description through, for example, the last paragraph on the first page, it

appears that forced outages associated with extensions to planned outages were a major part of the problem then, is that right?

A. That was a part of the problem, yes.

Q. If you look at the second page, let me just find the reference here, in the bottom paragraph of the second page, Mr. Franklin is trying to explain to the Minister the sorts of factors that could cause the problem to recur. And he refers to, in the third line of the last paragraph, "failure of generating units at Bruce and Pickering to return to service from outages on time." That again, that would be treated as forced outage, right?

A. In this case it would be.

Q. Now, do forced outages also include situations where you have to advance planned or maintenance outages when you don't want to? For example, you had a problem with pressure tubes. Instead of replacing them after 30 years, you had to replace them after what, 13 years or something at Pickering? That is a forced outage, right?

A. Pressure tubes...

MR. SNELSON: A. The first major pressure tube replacement, which was Pickering Units 1 and 2, occurred because there was a rupture in one of

the units, and that and its similar unit had to be taken out of service, in the case of the damaged unit, to repair it; in the case of the undamaged unit, because there was a significant probability the same problem might recur, and we wanted to avoid that problem recurring.

Those outages, which I think we have already dealt with, were in the order of three to five years for those two units, were considered to be forced outages, and they are in the forced outage data, which Mr. Taborek has shown.

The definition of a planned outage is an outage that can be deferred to the next season or beyond, and the subsequent retubing outages, Pickering Units 3 and 4, and proposed retubing outages at some of the Bruce units, which are being done on a planned basis, can be deferred by a year or more, one way or another, and are considered to be planned outages.

Q. And the reason for that, if I understand it correctly, is from a reliability point of view, you don't have to worry that tomorrow you won't have that unit, because you know when you won't have that unit. So, you are planning for it in advance?

A. Normally, planned outages are scheduled for periods when they will have little effect

on the system reliability. Retubing outages, which are a year or longer and therefore it is necessary that the units be out through at least one winter peak and maybe two winter peaks, then they are accounted for in our reliability calculation by actually taking out the units that are on planned maintenance, or for winter peak periods in evaluating system reliability. So, they are accounted for.

Q. I realize that. So, normally, a planned outage would not really be a reliability problem, right? If you had a planned outage of a month, and you could put it in September, it is not a reliability problem.

A. It is a very small influence on reliability, because the probability of being a reliability problem in September is a lot smaller than in December.

One does have to be concerned about the volume of planned outages and whether that can, in fact, cause reliability problems to be as significant during lower load periods when you are doing planned maintenance, as it would be in high load periods when you are not doing planned maintenance.

Q. But longer planned outages, like pressure tubes, for example, amid anything that is more

than a year, I guess, while not as bad as forced outages, still have a much bigger relative impact on reliability, is that right?

A. They have the impact of losing the unit for that period. And that is accounted for.

Q. What about if you can't use a coal unit because of acid gas limits. You reach your limits and you just can't use it because you would be over your limits. Is that a forced outage?

A. I think it is a very unlikely situation that we would get ourselves into that situation. It is a situation which, in the operation of the system, the system is operated to try and avoid that sort of circumstance.

Q. But, Mr. Snelson, I didn't ask you whether it was going to happen. I'm just working on the definition of DAFOR.

A. It never has happened, and where I'm...

MR. BARRIE: A. It is not thought of as a forced outage. It is an energy limitation on all of fossil plant. The acid gas restriction is essentially an energy limitation. It limits the total amount of fossil you can produce in a year. So, as such, it is not a forced outage.

So, at one instance, if we had a capacity problem, we could put all of our fossil plant and run it for a day. That would not impact the annual emission target. So, as such, it is not a capacity reliability problem in that sense.

Q. It is December 15, 1991, you are already up to 280 gigagrams, and it turns cold. You can't turn on the coal units. Is it a forced outage or not? Is that going to be in the number?

A. In that dreadful circumstance that you have just described, it would be. We would have managed the system dreadfully to have got to that point.

Q. So, it would be a forced outage, yes.

A. Under that particular circumstance you just described, it would be. However, it would not occur, because we would not manage the system that way.

Q. Fair enough.

THE CHAIRMAN: I'm just not sure of the dividing line between what you call an energy limitation or restraint and an outage, where do you draw that line?

MR. BARRIE: Well, the energy limitation puts a limit on how many times we could run the fossil plant, how many terawatthours we could get from the

plant. So, we have to plan the year's production, so that we stay within the acid gas restriction.

On any given day, that doesn't limit the capacity, unless we get into the kind of situation that Mr. Shepherd just described, where you were very close to the limits, and you needed a lot of capacity.

...

[10:35 a.m.] This is part of reason our strategy for meeting the acid gas, during 1990 in particular when it was limiting, was that we would tend to be lower than the target throughout the early part of the year. We had taken our control actions early so that we would not, in fact, get in the position that you just described.

MR. SHEPHERD: Q. And the reason for that of course is that December is the month you are most likely to need the coal; right?

MR. BARRIE: A. December is one of the months that has the highest fossil burn, yes.

Q. This is totally an aside. But why wouldn't you just go to the government and say, "Listen, can we calculate our acid gas limits from October 15 to October 15?"

MR. TABOREK: A. Simply that there is no one time period exceptionally preferred over any other and the decision was made to pick one and that is the one that is being used. And we live with the pros and cons of that.

Q. Now, if you have an oil-fired unit and you run out of oil, you want to turn it on but there is no oil in the tank, is that a forced outage?

MR. BARRIE: A. That falls into

basically the same situation as I described, where again you have an energy limitation.

Q. But when it happens -- it did happen in December of '89, didn't it? Was that included in the forced outage of Lennox when it happened?

A. I am not sure. I am not sure how that was classified in the after-the-fact reporting.

Q. Mr. Snelson, do you know whether that was part of Lennox's forced outage?

MR. SNELSON: A. No, I don't, because forced outage rates and so on are used both for system purposes and for also for unit performance purposes. And from a system point of view, what you have described is a forced outage -- a forced problem.

Q. Yes.

MR. TABOREK: A. But it would not be appropriate, for instance, to incorporate those features in a reliability analysis, and we would not propose, for instance, to build a new generating station because Lennox ran out of fuel in one month. We would just get fuel to Lennox.

The same with the acid gas. If we experienced an acid gas problem, we would fix the acid gas problem. We would not build another generating unit of some kind to give a reserve margin.

Q. So, from your point of view you don't think that should be treated as DAFOR -- or DAUFOP I guess --

A. It shouldn't be included in the reserve margins for the future system.

Q. And when you calculate the reserve margins, you are essentially going from forced outage rates to get there, aren't you?

A. Yes, that's right.

Q. So, if you included it in the forced outage rates, then you get--

A. I would certainly take them out, yes.

Q. --the wrong reserve margin?

And what about if you have other environmental problems stopping a unit. Let's just hypothesize that the Ministry of the Environment comes into Lakeview one day, says, "We don't like how you are dealing with your fly ash. Close it until it is fixed. Period. Just, now, close it." Is that a forced outage?

MR. SNELSON: A. I don't know. It's obviously unavailability of the plant, but how it would be classified I don't know. We haven't had that circumstance.

MR. TABOREK: A. That same comment with

respect to impact on future reserve margin.

MR. BARRIE: A. In general although when with we derate a plant for whatever reason, we do take account of that in our DAFORs, yes, in reporting that. So, if we have a restriction because of emission problems, that would be taken account of. But the solution is to put that right, not to build extra generation.

Q. I guess what I am trying to understand is we have all of these charts of DAFOR and DAUFOP, and I just want to know what is in the numbers, what the concept is. It sounds like Mr. Taborek is saying that the concept is if it's a technical constraint, that is, if the thing breaks, and things similar to that, then that's forced outage. It sounds like you are saying though, anything that when you flick the switch it doesn't come on, that's forced outage.

MR. TABOREK: A. My comments are with respect to the use of numbers for calculating the required reserve margin on the existing system.

Q. So, then I take it, Mr. Barrie's concept of if you flick the switch and it doesn't go on, it is a forced outage.

A. Mr. Barrie is more expert at

categorizing these than I, yes.

MR. BARRIE: A. I was trying to give the example of the environmental restriction. We would certainly factor that into part of the forced outage. We have had to derate units. During 1990, one of our problems was derating some of the fossil plant because of visible emissions. And when we did that, that was factored into the forced outage rate, yes.

MR. SNELSON: A. That is an equipment failure. The reason that the opacity limits were being exceeded was because the precipitators were not working properly. And that is a failure of the equipment. If there isn't fuel in the Lennox oil tanks and Lennox is therefore not able to operate, then all the equipment at Lennox is operable. And I don't believe that would be counted in the forced outage rate of the plant.

Q. I am confused then. I'm sorry.

I mean, forced outage rate must mean something, right? I thought I just heard Mr. Barrie say that if you expect it to turn on and it doesn't - he didn't say this, but this was the concept I understood - if you expect it to turn on and you can't turn it on, it is forced outage. And I understand you to be saying it is only the case if the equipment doesn't work.

A. We can give you, I think, an undertaking to give you exactly how these events were classified. But, my understanding is that if it is a problem with the equipment in the station, it will be part of the forced outage rate of that station because the station manager and people who design and operate the station are measured against the forced outage rate of their plant.

And if it's a problem with the fuel supply, then that's something which the fuels division, and people such as that, have to deal with.

But the environmental problems that led the ratings, as I have said, were equipment problems. It showed up as an environmental problem, but the reason that it was not being met was because the equipment was not working as it was designed to work.

Q. And that is not dissimilar from the generator not working, the turbine not working?

A. That is very similar to not being able to produce the power because there is only three coal mills working instead of four, and so you can't get all the coal into the boiler because the equipment isn't working properly.

THE CHAIRMAN: What I am not entirely clear of is whether DAFOR and DAUFOP mean the same to

everybody. Are there different criteria for operations and for planning for those two? I would have thought that they would be the same.

MR. SNELSON: They are the same and there are fairly consistent definitions of many of these factors throughout North America through a system called GADS, which is Generation Availability Data System.

THE CHAIRMAN: Well, I guess it's those definitions that Mr. Shepherd is now exploring. And if they are set out somewhere, perhaps that would be helpful.

MR. SHEPHERD: That would be very helpful, yes.

MR. BARRIE: Well, they are set out in our standard OEB -- every year we give a definition of all of these factors.

MR. SHEPHERD: Q. Well, Mr. Barrie, that's true and I understand that. But you will agree, I think, that all of these questions that I have just been asking about, what is included and what is not, those OEB definitions won't tell you those answers, will they?

MR. BARRIE: A. Let me clarify. All equipment-type failures as Mr. Snelson said which cause

when I flick a switch and ask for the power and it's not available, if it is an equipment problem at the station for whatever reason, if I either can't get the unit or I can only get a part of the unit, it will go against DAFOR. The only caveat I have that I am not sure about is how we treated those energy-type limitations.

Q. That is non-equipment reasons why it doesn't work?

A. It is a non-equipment reason, and the two examples we have are the shortage of oil at Lennox where the machine was actually available and we could have generated it, but we were running out of oil. Or the acid gas, where if we had put the unit on we might exceed our limit. They are not treated in DAFOR.

But, as Mr. Snelson said, we can undertake to get exactly how they were treated in the statistics.

Q. And similarly with the example of, for example, a government body forcing you to shut down a unit because you are doing something wrong, which is not an equipment available, they just don't like what you are doing --

A. Well, in the example we quoted about the emissions, that would be an equipment failure, the

precipitators were not working properly, the Ministry of the Environment ordered us to shut down, that would be a DAFOR as well.

Q. But if, for example, in the Lakeview example I gave you where you just have to deal with your fly ash problem and you haven't yet, and the Ministry of the Environment eventually gets annoyed and says "Enough is enough, close it," that would not be DAFOR?

A. I am not sure of that.

Q. Just one more example quite different.

MS. PATTERSON: Do we have an undertaking number? Is that .54.

MR. SHEPHERD: Yes.

MR. BARRIE: Can we clarify exactly what it is we are giving in that undertaking.

MR. SHEPHERD: Q. My understanding of what you are giving is a detailed summary of where you draw the line between DAFOR and -- or forced outage and not forced outage in the context of non-equipment failures.

MR. BARRIE: A. Okay.

Q. Now what if you have technical or other problems during the shakedown period for a unit.

The specific example, which is probably the easiest to mind, is Darlington because it was supposed to be on the line, what, a year ago? Two years ago? And it keeps changing.

Now, when it has technical problems after its in-service date, its proposed in-service date, but before it is actually commissioned, is that DAFOR?

A. It is the actual in-service date that is the critical thing here. When it is declared in-service, any subsequent problems will go against DAFOR.

Q. But any problems you have before it's commissioned --

A. Well, it is being commissioned then. A unit being commissioned, naturally, is subject to more outages. In fact, we don't even count on it at the control centre. When we are getting power from a commissioning unit, we know that it is inherently less reliable until it is officially declared in-service, and we, in fact, alter the way we treat that plant during its commission.

Q. So, the variability and the reliability of a particular technology, say, or a particular unit from -- let me rephrase this.

There is a fairly predictable pattern of

problems that you will have during commissioning, right, that's the whole point of having a shakedown period?

A. The unit during commissioning will not be as reliable we expect as it will be when it is steady operation, yes.

Q. And in a case of something for example like Darlington where it has been far less reliable, you keep having to put back the in-service date because things keep breaking, you wouldn't treat that difference as being a forced outage?

A. Unless it has been declared in-service, it is not treated as part of DAFOR, yes.

THE CHAIRMAN: Excuse me. I thought somebody said some time earlier that you estimated its in-service date for your planning purposes, and then moved around that with a 6-month margin. Now, you are saying that you don't take into account until the actual date. I am a little confused about that.

MR. SNELSON: I think both statements are correct. DAFOR, as Mr. Barrie has said, does not include the possibility that the actual in-service date may be later than the planned in-service date.

For planning purposes, in the reliability model, we have a factor called "in-service date

uncertainty" which is in addition to DAFOR, which I originally said went from 6 months early to 18 months late; and since, we have corrected the transcript as being 6 months early to 12 months late. And that analysis was based on some past experience of the actual in-service date uncertainties that we had experienced.

MR. SHEPHERD: Q. Is in-service date uncertainty in the reserve margin calculation? I think I recalled that you did have something like that.

MR. TABOREK: A. Yes.

MR. SNELSON: A. Yes.

Q. By the way, do I understand correctly that you don't treat the station as being in-service until two units are commissioned?

MR. BARRIE: A. No.

MR. SNELSON: A. No.

MR. BARRIE: A. Each unit is separately treated for in-service day.

Q. I am going to ask you to look at Exhibit 148, the 1990 version. Could you just give me a minute until I find my copy. If you look on page 1. I'm just going from memory now, about, I think, the middle of the second paragraph.

...

[10:50 a.m.] THE CHAIRMAN: What page, please?

MR. SHEPHERD: This is page 1 of the 1990 reliability indices.

THE CHAIRMAN: Exhibit 148?

MR. SHEPHERD: That's right. I'm sorry, it's page 1 of the forward of that. So, it's not even a numbered page, actually.

Q. Do you see where I am? If you look at the third paragraph, the sixth line, it says: "Stations with half the units commissioned at time the forecast is prepared are considered to be in-service." Is that something different?

MR. TABOREK: A. Allow me to clarify that. That's with respect to the allocation of the primary responsibility for making the forecasts. It's not the definition that Mr. Barrie was talking about.

Q. All right, okay. Anyway, where I was going was, if in the most extreme situation, it's October 31st, you still believe that Darlington 1 is going to come on in-service on November 1st, you are scheduling tomorrow and you get a phone call, "No, sorry, we are going to have to put it off another month." I realize it's very extreme, but in that situation that is not DAFOR; is it?

MR. BARRIE: A. I don't think it is.

Q. I realize that would never happen.

A. Never say never. (laughter)

Q. Okay. Can you turn again to - I am using 148, I didn't realize that - Exhibit 148, the 1990 reliability indices, page 19. What I would like to do is talk for a minute about the forced outage rates you are using for --

THE CHAIRMAN: 19, so Table 14.

MR. SHEPHERD: Table 14, yes.

Q. I would like to talk just for a minute about the DAFORs you are assuming for NUGs. If I understand this correctly, the DAFOR you are assuming for NUGs is 15 per cent; is that correct?

MR. TABOREK: A. Yes.

Q. And that's made up, if I read the last three lines correctly, last two lines correctly, of 5 per cent for real forced outages, which is sort of like your definition of equipment failures, and 10 per cent for something called steam process derating. Can you explain what steam process derating is?

MR. SNELSON: A. I can give you the first level of description, beyond that, as I say, you can go to Panel 5 which is the non-utility generation panel.

But, this is on the basis that most of

the non-utility generation that is in the non-utility generation plan is cogeneration. And as I described yesterday, cogeneration is usually operated in a mode where the electrical energy production is as determined by the steam demand. And the judgment is that the electrical operation is usually somewhat lower than the maximum amount of electricity that the facility could produce, its maximum capacity, and that the 90 per cent or the 10 per cent steam derating is an allowance for the electrical production being a little bit lower than the maximum because the steam demand is usually a little bit lower than the maximum the facility was designed to produce.

So, that's as far as I can take you. Anymore detail of that would have to go to Panel 5.

Q. So, if I understand that correctly then, you are assuming that if a cogenerator has a drop in the demand for process heat, the electricity output will go down the same amount?

A. It's not a drop in the demand for process heat. It's assuming that he has built some margins into his steam supply system such that his steam demand is usually a little bit less than the maximum the facility could produce, and that the electricity demand would be correspondingly a little

bit less than the maximum electricity that the facility could theoretically produce.

Q. That assumes, I guess, that the thermal load and the electrical load are matched by the cogenerator; correct?

A. More or less, yes.

Q. That's in fact true in the United States; isn't it? It's very common in the United States to have close matching of load?

A. This is where I think you would have a more definitive answer from Panel 5.

Q. So, if I want to ask questions about forced outage rates of non-utility generators, that should all be Panel 5 questions?

A. Yes, I think we can deal with how the non-utility generation is modelled in the overall system reliability calculation, but the reason why the availabilties are set, as described here, are better dealt with by Panel 5.

Q. Do I understand that these numbers in fact aren't even set by your group, the non-utility generation division --

A. I'm sorry, I missed the question.

Q. Do I understand correctly that these numbers are not produced, these numbers on Table 14,

are not produced by system planning, or indeed by the operating division, they are produced by the NUG division?

A. The way in which all of these numbers in Exhibit 148 are produced is that the production of the document is coordinated by system planning division, but the most knowledgeable group on each type of capacity contributes to that. So, the non-utility generation numbers have been contributed by the non-utility generation division, in discussion with others.

Q. Okay. I am going to leave that series of technical questions then on those things, but I do have some clarifications that I would like to get to.

If you could turn to the 1989 forecast of reliability indices, which I believe is also part of 148; isn't it? Exhibit 148 is all three of those sets?

THE CHAIRMAN: It's the one dated March 1989?

MR. SHEPHERD: No, it's the one dated March 1990, I think.

THE CHAIRMAN: Right.

MR. SHEPHERD: Q. And if you will turn to page 22. As I read that, and I don't even actually

have it in front of me, but as I read it last night, that says that your assumption then was a 10 per cent forced outage rates for NUGs; is that correct?

MR. TABOREK: A. Yes.

Q. And I think it was you, Mr. Barrie, who was asked last Thursday - and your transcript reference for this is page 3221 - you were asked, do you use a 10 per cent forced outage rate for NUGs and you said yes; is that right? Or maybe it was you, Mr. Taborek.

MR. BARRIE: A. I don't recall that.

MR. TABOREK: A. I do recall giving a number of 10 per cent to one of the questioners.

Q. Was that wrong then?

A. No, there is the number.

Q. But that was the previous year's number; wasn't it? Isn't your new number 15 per cent?

A. Yes. And I answered in respect to what is in the F&D model and the F&D model has the 10 per cent number in it.

MR. SNELSON: A. Maybe Mr. Taborek can just tell us which edition of the F&D model he is talking about. Because I think if we were to redo frequency and duration analysis now, it would be based on the latest forecast.

MR. TABOREK: A. That's right.

Q. So, it would have 15 per cent?

MR. SNELSON: A. Previous predictions using the F&D model.

MR. TABOREK: A. That's correct.

MR. SNELSON: A. The ones described in 87, the ones described in Exhibit 87 were the 10 per cent.

Q. All right.

THE CHAIRMAN: Is is it in 87?

MR. TABOREK: Yes. The F&D model that was used to compute the work that was done in Exhibit 87 used a 10 per cent forced outage rate for NUGs, for CTUs and NUGs.

THE CHAIRMAN: If you were doing 87 now, you do 15 per cent; am I right?

MR. TABOREK: Yes.

MR. SHEPHERD: Q. Just help me out a bit here. Will you turn to 2.14.30?

MR. TABOREK: A. Yes.

Q. And this may actually be a question for Mr. Snelson. The last line of 2.14.30 says that for avoided cost calculations you use a DAFOR of 5 per cent for NUGs. It says, more recently, avoided cost calculations have used a DAFOR for NUGs of 5 per cent.

MR. SNELSON: A. And that would be 5 per cent relative to the expected amount of power being produced at the time of peak load.

So, in terms of calculating the avoided cost of a specific non-utility generator, then either through the data he provided to us, or through data that would perhaps be estimated by our non-utility generation division, one or the other, then we would have an estimate of the amount of power that was expected to be produced and to be on line at the time of peak load.

And, if the steam derating factor that we talked about was significant, that would be accounted for in the amount of power expected to be available at the time of peak load, and at that point, the steam derating is already accounted for if it's a factor in that particular non-utility generator, and the additional forced outage rate to account for in the avoided cost calculation is on the equipment unavailability which is reckoned as 5 per cent.

Q. So, this DAFOR here is a different DAFOR than Mr. Taborek's DAFOR?

A. Mr. Taborek's DAFOR is relative to the reported capacity of the non-utility generator as in his contract, or whatever, that is reported to us

through the non-utility generation plan, and is used to evaluate the reserve requirement for the system as a whole.

When we are looking at the avoided cost of a particular non-utility generator, then we are very careful to make our evaluation of that non-utility generator as specific and as accurate as we can make it for that particular non-utility generator's circumstances.

So, there are broad assumptions that may be made for a system evaluation which more accurate assumptions will be made for a specific evaluation of a particular non-utility generator, given that you then have more data to deal with and it is more appropriate at that stage to do a more detailed calculation.

Q. Mr. Taborek, just looking at your reliability calculations for a second, and reserve margin calculations, is there an impact if, let's say, two stations, whatever they are, have the same capability factor but one has a much higher forced outage rate and lower everything else, and the other has a lower forced outage rate but more maintenance outages and planned outages, et cetera. Would they have different impacts on on how you calculate reliability and reserve margin?

MR. TABOREK: A. Reliability --

Q. Sorry, reserve margin.

A. Reliability and reserve margin are primarily impacted by the forced outage rate.

Q. So, if you have some like steam process derating and you choose to treat it as a forced outage rather than something else, then that will tend to depress the reliability of NUGs; is that right?

MR. SNELSON: A. I think this is somewhat similar to the long planned outage for the nuclear plant that we have talked about. The important factor is, will that capacity be available at about the time of peak load, and we are talking about peak load that could occur perhaps in any three of the winter months, December, January, February.

If it was steam derating that only occurred during the summer, then it would probably not be impactive on reliability. If its steam derating that occurs most of the time and is likely to occur during the peak months, then it would be impactive.

...

[11:05 a.m.] Q. I would like you to turn, if you could, please, to Exhibit 161, which I gave you yesterday. What I would like you to do is just look at -- let's start with the back page. These are the larger non-utility generators in California, as I understand it.

Now when I look at the line that says EAF CF, that is something fairly equivalent to capability factor, isn't it? In the context of cogeneration unit with ample fuel, that would be very similar to capability factor, wouldn't it?

A. Does this document have a definition of EAF on it? Other than CF? Is CF capacity factor?

Q. It is on the previous page. EAF is equivalent availability factor and CF is capacity factor.

A. I understand the common meaning of capacity factor. What is puzzling me about this exhibit is why there would be one column with equivalent availability factor and capacity factor, why they would be the same thing.

Q. If you assume they are non-dispatchable, then those two numbers would be identical, wouldn't they?

A. From a power system point of view

perhaps, but maybe not from the equipment point of view. The fact that a non-utility generator chooses not to run to his full availability doesn't change the availability factor of equipment.

Q. But from the utility's point of view, the non-utility generator is an external source of supply, so, he is either on or off it. He is either there or he isn't.

A. As I said, from a system point of view they may be the same thing.

I'm happy to discuss it in terms of capacity factor, presuming that is what the definition of the column is.

Q. I'm just looking down this list and looking at the cogen facilities, because that is what we are really talking about here. That is what your chart is about, right, thermal NUGs is cogen?

A. Yes.

Q. So, just looking at the cogen facilities, it looks like their capacity factors are way, way above the sort of thing you are expecting for NUGs in the Table 14 of the 1990 reliability indices. You are expecting something around 80 per cent, right?

THE CHAIRMAN: Would it be 85?

MR. SHEPHARD: No, I think it would be

80. Because they also, in addition to the 15 per cent forced outage rate, they also have a 5 per cent planned outage rate.

THE CHAIRMAN: I thought it was ten and five and fourteen.

MR. SHEPHARD: That was in 1989. Then in 1990 they changed it to 15 and 5.

Q. Isn't that right, Mr. Snelson?

MR. SNELSON: A. You're back to Exhibit 148, 1990 report?

Q. 1990, page 19?

A. That is page 19, I believe.

Q. Yes.

A. The median incapability factor that is shown there is 20 percent, which implies a capability factor of 80 per cent.

Q. And capacity factor can't be more than capability factor, can it?

A. Provided the definition of capacity that you are measuring it against is the same, you are correct.

Q. It is just mathematically impossible, right?

A. Yes.

Q. Okay.

A. Provided the definition of capacity as the same.

Q. So, with the one exception of a brand new facility in the Mojave Desert, it looks to me like all of the cogeneration facilities on this list are way above that. Is that right?

A. These are your numbers, yes. I...

Q. Actually they are the California Energy Commission's numbers, not mine.

A. I am not in a position to discuss the relative magnitude of cogeneration facilities' availability in the States versus here. As I have said, the justification for the numbers that we have given will be better addressed to Panel 5.

Q. So, you don't know anything about QFs in the United States, do you?

A. It stands for qualifying facilities.

Q. But if I were asking you questions about how you qualify and stuff, that--

A. No.

Q. --would be Panel 5, right?

A. Yes.

Q. Let me then, just before we leave the question of forced outage rates, isn't it true that a forced outage rate for a single unit of certain

capacity, if compared to the forced outage rate -- the same forced outage rate for a lot of small units totaling the same capacity, in the latter case you are going to have a lot more reliability? Isn't that right?

A. You are going to have more. I'm not going to necessarily agree to a lot more, because that depends on the ratios of unit sizes and system sizes.

Q. Fair enough. I'm going to ask you to turn to Exhibit 162, and you have had a chance to read this now?

A. I read it at home last night.

Q. I'm not going to quiz you on the tables of numbers. However, I do want to look at the graphs at the end, which, at least on my copy, are numbered upside down.

I'm going to show you Mr. Marks' first chart, which is an overhead. I think it is overhead No. 13 of that package. It is also the fourth last page of the exhibit we are talking about. It is labeled "NUG reliability at 8 per cent forced outage."

All this shows, correct me if I'm wrong, all this shows is the cumulative probability of generation from twenty 44-megawatt NUGs totaling 880 megawatts, using the same forced outage rate as you

often used for nuclear eight per cent. And does that look like it is the right answer, the cumulative probability?

A. It looks generally right.

Q. Doesn't that show that when there is an eight per cent chance that the nuclear unit isn't producing power, there is almost a certainty that the NUGs will be producing 704 megawatts?

A. In this particular, very artificial example, yes.

Q. Why is it artificial?

A. Because you are comparing a reliability of a system with one large unit, with a system with 44 small units.

Q. Well, if you had a choice between getting 880 megawatts from cogenerators or 880 megawatts from building another unit at Darlington, wouldn't the comparison be accurate in terms of the impact of the forced outage rates?

A. The factor that matters is the reliability of the whole system, not necessarily the reliability of the little piece that you add. So, you are interested in the effect on the whole system and not on just the addition.

Q. Well, we haven't done a chart of the

whole system, of course, but if you look at the last page of Exhibit 162.

DR. CONNELL: Excuse me, Mr. Shepherd, I don't think I follow the point with respect to -- what does this say about the nuclear unit to which you are drawing your comparison?

MR. SHEPHARD: Well, if you have a nuclear unit that has an eight per cent forced outage rate, then at any given time...

DR. CONNELL: That is purely hypothetical, isn't it?

MR. SHEPHARD: It is their number.

DR. CONNELL: From what source?

MR. SHEPHARD: I think the 1990 reliability indices use a long-term forced outage rate for nuclear of eight per cent. Isn't that correct?

MR. TABOREK: Near enough, yes.

MR. SHEPHARD: Yes. So, at any given time, the whole 880 megawatts has an eight per cent chance of not being there. I'm oversimplifying, but that is basically it. Whereas, at any given time there is a virtual certainty that 704 megawatts of the equivalent NUGs will be there. You don't have to worry about that amount. You do have to worry about above that. But that 704 megawatts is virtually certain.

That is simply because of the probability of more than one of them being off at once, and the probability of two being off and three being off at the same time, all with the same forced outage rate.

DR. CONNELL: You're asking the Panel to draw some inference from that?

MR. SHEPHARD: I will be in a minute, yes.

Q. So, Mr. Snelson, if you could look at this last chart, which is graph 4 of Exhibit 162, the last page of Exhibit 162, and what this does is it compares a four-unit nuclear facility like Darlington against an equivalent number of smaller NUGs. Same binomial probability calculation, okay?

If I'm right, then the portion between the two lines, that is below the black line and above this crosshatched line, that portion is the NUG reliability advantage. Is that a fair expression?

MR. SNELSON: A. In this extremely artificial example, yes. I don't believe it has any significance to the Ontario Hydro system.

Q. I will come back to that.

But then after you get to a 3320 megawatt number, it is actually less likely that you are going to have the NUGs, that much NUGs, than you are going to

have the nuclear unit, right?

A. In this artificial example, yes.

Q. But from 1760 megawatts, by my calculations, to 3320 megawatts, you are more likely to have the NUG capacity than you are the nuclear station?

A. In this artificial example, yes.

Q. Is it true that the more small NUGs you have, the higher the amount of capacity you have that is mathematically virtually certain on your system? Did it take you the whole system-wide basis?

A. It is directionally true that more small units will have a higher degree of reliability than a few large units.

Q. What I'm trying to get at, though, Mr. Snelson, is this notion that there may be, if you have enough small units, then you may have a chunk of capacity that has virtually no uncertainty that it is going to be there. So small as to be unmeasurable?

A. If you take your first example, with any combination of small units or large units that form together into a system, then at whatever statistical level of certainty you want to establish, there will be some level at which you have a high degree of confidence that you will always have that much capacity. And that is true for both small units and

for large units, and the number will be slightly different.

Q. Well, isn't it true that the -- that if you use small units rather than large units, the number is not slightly different, it is significantly different? Isn't that true?

A. It is true that the number is different, and whether it is significant or not, you have to do the reliability calculations with the real proportions of small units and large units that are in the system to determine how big the difference is, and whether, in fact, that is something that should be considered to be significant.

Q. Do your operating models assume a reliability advantage for NUGs? Do they assume that if you have a lot of small units, you have more certainty of having that power?

A. Yes.

MR. TABOREK: A. Excuse me, operating model?

MR. SNELSON: A. The F&D model.

MR. TABOREK: A. F&D, reliability.

Q. Yes, the F&D model.

A. Yes.

MR. SNELSON: A. Yes.

Q. And from an operating point of view, on a day-to-day basis, do you assume -- or you don't have enough NUGs to assume it yet, but let's assume you had 5,000 megawatts of NUGs. Would you then have to make some sort of assumption as to their higher reliability, in order to operate?

MR. BARRIE: A. Yes, we would have to.

Q. Sorry?

A. Yes.

Q. Are you aware of any utilities that as a result of increases in the quantity of NUGs on their systems, have been able to reduce their reserve margins?

...

[11:20 a.m.] A. I am not aware of it.

Q. Mr. Snelson?

MR. SNELSON: A. I am not aware of any, but --

Q. It's Mr. Taborek's area. Have you looked at that at all?

MR. TABOREK: No. I am not aware of any.

Q. You haven't looked at that at all, you haven't looked at that question?

A. No, I have not investigated other utilities' responses to the introduction of NUGs.

Q. Ontario Hydro does intend to substantially increase the percentage of NUGs on the system, doesn't it?

A. Yes.

Q. But as I understand what you are saying, you haven't taken any steps to figure out what that would do your reserve margin by comparing yourself to other utilities?

A. We have taken steps to determine what it would do to our reserve margin.

Q. But not by comparing yourself to other utilities.

A. Correct.

Q. Although in all other aspects of your

reserve margin you have, in fact, compared yourself to other utilities; isn't that correct?

A. No, not in all other aspects of our reserve margin. What we did was compare the reserve margin we had against other utilities and looked to account for significant differences.

Q. Am I right in assuming that or in concluding, I guess, that if the capacity factor numbers that that we saw in that California Energy Commission excerpt, if those are representative of NUGs, just assume that hypothesis for a second, then the capacity factors, the capability factors, if you like, for NUGs, would be far superior to either nuclear or fossil in your experience in Ontario?

MR. SNELSON: A. you are talking about 10 or 15 per cent unavailability.

Q. The averages look like somewhere between 7 and 13, I think, actually.

A. I thought it was 15, but anyway. You know what our unavailability forecasts are, they are in 148, for plant, and those are lower numbers than the unavailability that we forecast for fossil and nuclear plant. Though we have had years when nuclear units have operated at capability factors in excess of 90 per cent. So, generally, those are better availability

factors than we forecast.

Q. And if you look at the past history of nuclear fossil, isn't it true that those availability numbers are really very significantly better than your past history, not to suggest that you are going to repeat your past history, but if you just make that comparison, it is a pretty big difference; isn't it?

A. The unavailability is -- that is quite a good unavailability -- no amount of unavailability.

MR. SHEPHERD: Mr. Chairman, I am going to turn to reserve margins now. I wonder if you want to take the break early.

THE CHAIRMAN: Why don't we take the break now and come back in fifteen minutes.

---Recess at 11:25 a.m.

---On resuming at 11:45 p.m.

MR. SHEPHERD: Q. Let me turn to reserve margins. Is it right that you have different appropriate reserve margins for different generation technologies? Mr. Taborek?

THE CHAIRMAN: I'm sorry, I didn't hear that question.

MR. TABOREK: Repeat your question,

please.

MR. SHEPHERD: Q. Different generation technologies have associated with them different appropriate reserve margins; is that correct?

MR. TABOREK: A. Where we compute a system reserve margin and the system reserve margin would be different if your system were made up of technologies with different characteristics.

Q. You don't compute reserve margins associated with individual options. Nuclear, for example, what's the appropriate reserve margin for nuclear?

A. Not for a system reserve margin.

Q. I recall - I don't remember where it was - that somebody said that you use a 24 per cent reserve margin for fossil, a 24 per cent reserve margin for nuclear, and something else - I don't remember what it was - for hydraulic, on your own system.

A. No, I don't recall ever saying that. I don't know anyone else that would say that either.

MR. SNELSON: A. 24 per cent is the estimate of system reserve margin of the Ontario Hydro system as it will be in the sort of 2000 to 2005 time period, taking into account the mix of technologies, demand management, non-utility generation. Everything

that is captured in the frequency duration models as described in Exhibit 87.

Q. I would like you to turn to Exhibit 160. This is entitled "Excerpts from Documentation for the Delta Computer Program Set-up." Perhaps you could just start by telling us us what the Delta computer Program was or is.

A. The computer program that is being referred to, being given the name Delta, was a program that was used to calculate system incremental costs which is a major determinant of avoided cost, prior to the development of the Demand/Supply Plan.

Q. So, this was the precursor to LMSTM in effect; is that right?

A. No.

Q. You used that for system incremental costs before you used LMSTM for system incremental costs. Or am I understanding that totally wrong?

A. To run the program called Delta, you needed to have the results of an energy production model. LMSTM is an energy production model. Delta was really sort of a post-processor to an energy production model.

Q. You are not using it anymore?

A. We don't use Delta now, no.

Q. You were using it in '88, weren't you?

A. It was used up until the development of the avoided costs that are shown, and the system incremental costs that are shown in Demand/Supply Plan, yes.

Q. I am not sure I understand. So, just before you started to calculate the system incremental costs for the Demand/Supply Plan, you changed to something else.

A. Yes.

Q. So you didn't use Delta for the DSP?

A. During the development of the Demand/Supply Plan, we changed our avoided cost calculation to be based on a specific long-term plan, namely Plan 15 of the Demand/Supply Plan. In that process, we went from a somewhat general model, which is described in this Delta program, to a more specific calculation that is related to the specific program, specific plan that is in the Demand/Supply Plan.

So, in going from one method to the other, then we changed the programs at the same time to be appropriate to the new method.

Q. I don't really want to get into the avoided costs.

A. No, I think that's Panel 3.

Q. I just want to identify the...

If you look at the last page of this, page 2 it's marked, this is an excerpt from the process you go through to determine the avoided costs using this model. And what it says under nuclear initial run, it says "reserve requirement 27.7," which I presume is per cent; and under coal, it says "reserve requirement 21.03," I assume again per cent; and under oil it says "reserve requirement 27."

So, is that the sort of thing I was asking earlier, that is, separate reserve margins for different generation technologies?

A. I don't know what you were asking earlier. But I can tell you what this is.

Q. Okay, that would be good.

A. This is derived from an estimate of the load meeting capability of an additional amount of nuclear generation or fossil generation on the system. So, this is an incremental effect on the system reserve margin and it's a description really of the load meeting capability of that particular type of capacity as an addition to the system.

Q. So, is it fair to draw the inference from it then that you need more nuclear to have the

same load meeting capability that coal?

A. With the data that went into determining those load meeting capabilities, yes.

Q. Is that true today?

A. I believe it is.

Q. When you run your F&D model, is that assumption implicit in it that you need more nuclear to have the same load meeting capability as you would get from coal?

A. The load meeting capability of the generating unit is determined principally by the forced outage rate of the unit, and to a lesser extent by the unit size.

And the F&D model takes together all of the units with their appropriate data and determines a system reliability which is then used, as Mr. Taborek described in his direct evidence, to determine an appropriate reserve margin for the system as a whole. So, you would never find in the F&D model an estimate of the reserve requirement for any particular generation. It calculates the effect of the whole system.

But, because the units that go in have different sorts of data, then you can infer that they would have different incremental effects upon reserve

margin. It is not calculated.

Q. Let me simplify this just a bit. If you take a look at these numbers from Delta, and I understand those numbers aren't relevant today, they just happen to be a good example, that's all, and you look at the reserve requirement assumed for nuclear of 27.7 per cent, do I take it then that a thousand megawatts of nuclear is assumed in this to be 823 megawatts of load meeting capability?

A. No. I don't believe so.

Q. Sorry, 723.

A. I think you have to be divide by 1.27.

Q. So, it is actually less then? No, it is actually more, that's right.

A. Sorry, what number did you give me.

Q. Let me change the example. 1277 megawatts of capacity would be a thousand megawatts of load meeting capability. That works; right?

A. Yes.

Q. Okay. I have this problem in U.S. exchange, too.

And similarly in coal, then 1210 megawatts would have a thousand megawatt load meeting capability; right?

A. Yes.

Q. And implicit in this then is a higher incapability factor for nuclear than for coal; is that correct?

A. Yes. And it may also be a slightly larger unit size.

Q. All right. And that's back to that small unit/large unit thing we were talking about earlier. Is that the same concept?

A. Yes.

Q. Now, your new projections of incapability factors for coal and for nuclear, in general, is it now true that nuclear has a lower incapability factor than coal? In your projections? I don't want to go into the detail, although if we have to we will, but is that sort of generally true?

MR. TABOREK: A. I would just check them in the exhibit.

...

[11:55 a.m.] MR. SNELSON: A. For future units of comparable size, the incapability of a 4 by 750 megawatt nuclear station is forecast to be 18 per cent in the long run, and for 4 by 850 megawatts nuclear, it is forecast to be 16-1/2 per cent. But the forced outages are in the opposite relationship.

THE CHAIRMAN: Sorry, 4 times 750, what did you say?

MR. SNELSON: Four times 750 megawatts units.

THE CHAIRMAN: Of?

MR. SNELSON: Of coal, bituminous coal. That's on page 27 of Exhibit 148, the most recent version of Exhibit 148.

DR. CONNELL: This is CTUs, I take it.

MR. SNELSON: No, this is coal.

MR. TABOREK: These are large coal generator stations.

MR. SNELSON: Large coal generating plant. It is shown as having a median incapability factor of 18 per cent in the long run. Four by 850 megawatt nuclear units, which is on Table 18, page 23 of the same report, is shown as having a median inability of 16-1/2 per cent, which shows the nuclear as having lower incapability than the coal.

As I said, the forced outages are in the opposite way around; the nuclear is higher than the coal.

THE CHAIRMAN: Do you have numbers for the forced outages?

MR. SNELSON: Yes. The DAUFOP for the coal-fired plant correspondingly is 5 per cent, and for the nuclear plant it's shown as 8 per cent.

MR. SHEPHERD: Q. Now, of course, the DSP doesn't have any coal units in it, does it.

MR. SNELSON: A. Case 15 doesn't.

Q. Okay. Fair. And if we were looking at your projections for your existing coal units and your existing nuclear units, Panel 2 is on existing system and I am trying to keep it to that, isn't it fair that you are expecting higher incapability and higher forced outages in fossil and nuclear, on average?

A. I haven't averaged it across the system. I am sure there must be units that go one way or the other. The data is all there in Exhibit 148.

Q. If that were true, let's assume it is for now and we will get the calculations done, that would suggest, if you were doing a calculation like this, like in Delta, would it not suggest that you

would have a lower reserve requirement for nuclear and a higher reserve requirement for coal? I am not saying you do this, but if you did to that, what you did in Delta, you would then have to reduce the nuclear reserve requirement and increase the coal reserve requirement?

A. No.

Q. No? Well, a higher DAFOR means a higher reserve requirment, doesn't it?

A. Yes.

Q. So, your coal DAFOR is higher than your nuclear DAFOR?

A. Not for new units.

Q. All right. But we are talking about existing units now.

A. If we are doing an incremental cost calculation, then we are talking about new units. If we are doing an incremental power calculation, we are talking about new units.

Q. All right. Let me come back at this another way.

You are proposing in Plan 15 to increase the reliance within the Ontario system generation on nuclear, isn't that correct, as a percentage and as an absolute?

A. Not to my knowledge.

Q. Plan 15 doesn't include an increasing percentage of nuclear generation as compared to --

A. I believe by the end of the plan period the per cent of nuclear generation in a total sense is about the same as it will be in 1993 when Darlington is in-service.

Q. All right. Is it true that as you increase the amount of load-following options, you would tend to decrease the reserve margin; is that right, that you would need?

A. Not to my knowledge.

Q. Mr. Taborek, really this is your area; isn't it?

MR. TABOREK: A. I have nothing to add.

Q. So, you don't think that load following would naturally decrease your reserve margins, no?

A. Nothing to add.

Q. Fine.

THE CHAIRMAN: I'm sorry, I didn't get the answer. What did you say?

MR. TABOREK: Nothing to add to Mr. Snelson's comment.

THE CHAIRMAN: Fine.

MR. SHEPHERD: Q. And Mr. Snelson's answer was, no, it would not reduce reserve margin; is that correct?

MR. SNELSON: A. Not to my knowledge. You would have to be far more specific about the characteristics of the options that you are talking about.

Q. Let's be more specific then. I am going to hypothesize two load-following options and I am going to hypothesize an option that dramatically reduces space heating in all sectors. I don't care what it is. It's an incentive program, let's say. And I am going to hypothesize regulations that require more efficient commercial lighting systems in commercial buildings. Just take that combination, that's your load-following option, those two things. Let's say it's a lot.

A. Is this one option or two options?

Q. One option, together. The Energy Efficiency Act, 1992.

If you have that situation, and it is a significant number, assume it's a significant number, would that tend to cause you to reduce your reserve margin?

A. Not necessarily.

Q. And when you say "not necessarily," what do you mean?

A. There are a number of factors that work in opposite directions.

To the extent that part of your option package was a reduction in loads that would occur at the time of peak load, then that would reduce the amount of capacity that you use to establish your reserve margin -- the amount of load, sorry, that you use to establish your reserve margin. The reserve margin is calculated as a percentage of the peak load.

Q. Yes?

A. So, having reduced the peak load, you would definitely reduce the amount of capacity you need.

Q. Calculated absolutely as opposed to as a percentage?

A. Calculated in megawatts terms.

Q. I am asking about the percentage.

A. As to the per cent reserve of the new peak load, then you have to take into account such factors as what has happened to the variability of peak load, you also have to take into account to do this calculation that by reducing the peak load more than the load at other times, load curve has now become

flatter. And so, if you are at risk from a reliability point of view when you are close to peak load, you are now going to be close to peak load for a higher proportion of time. So, the risk due to the load being high for a large proportion of time is not accounted for in your example. And it would be a very difficult exercise to definitively determine whether the reserve margin went up or down as a result --

Q. And there is no generalization you can make about that then?

A. No.

Q. Let me ask a question about the high load factor thing you were just talking about. This is something that has confused me since you mentioned it in direct, or Mr. Taborek did.

I understand your evidence to be that a utility will generally like to increase it's load factor.

MR. TABOREK: A. Yes.

Q. But I also understood your evidence to be that as you increase your load factor, I am not sure whether you have to increase your reserve margin or you have more a reliability problem because your peaks are longer; is that...

A. As Mr. Snelson just described, when

you get into trouble you tend to get into trouble for longer periods, simply stated.

Q. Okay. Which would tend to mean that you don't like a high load factor; is that right? Maybe it's not important.

A. Yes.

Q. Yes, you don't like a high load factor or yes, it's not important?

A. Yes, you don't like a high load factor for that reason. And I think there are pros and cons to having higher load factors.

Q. Okay. Is it fair to say that if you increase the nuclear component of a system, you will generally require a higher reserve margin, all other things being equal?

MR. SNELSON: A. It depends what system it is that you are increasing it from.

Q. So, there is no generalization you could make there, that it will tend to do that, say, or or more often than not?

A. If the numbers that you have given us here, if you have an option that you are adding to a system that incrementally has a load-meeting capability, such that it is less than the average load-meeting capability of the system, then that would

tend to move your reserve margin up.

If you had an option that incrementally has a load-meeting capability larger than the load-meeting capability of the system, that would tend to move your reserve margin down.

The system is like an average, if you like, and if you are averaging into the base something which is higher than average, it's moving the average up, if you are averaging something to the base that is lower than the average, it is moving the average down.

Q. I guess I understood, and maybe I am just wrong here, but I guess I understood that the extent to which an option was move flexible would change its impact on reserve margin; that is, nuclear, for example, you essentially run flat out. So, the more that you have, the less flexibility you have in your system; isn't that right?

A. Flexibility and reliability are slightly different concepts.

Q. Well, if you have more flexibility don't you have more reliability, generally speaking?

A. The tendency would be in that direction, but I am not sure that it is necessarily a significant factor.

Q. Is it also fair to say that increased

non-utility generation will generally result in a decreased reserve margin, all other things being equal?

A. To some degree, yes, presuming it has higher load-meeting capability than the system average.

Q. I only have one other issue to deal with on the subject of reliability. You talked about this a little bit, and that is common mode failure. And just so we don't get into the same problems as we had with DAFOR, could you take a crack at defining common mode failure?

MR. TABOREK: A. It is a failure that effects more than one unit at a time, and by contrast, other failures that don't have common modes, each unit fails in a totally independent manner.

Q. It's also referred to as common cause failure for that reason?

A. Yes.

...

[12:12 p.m.] Q. Would you say it is restricted to technical problems as with DAFOR equipment-type problems, or is it a broader concept than that?

A. Well, It would depend on what you were using the concept for, because it is just a concept at the moment. If you were going to take that concept and apply it to reliability calculations, it would be the DAFOR description that we had used earlier.

Q. So, are the problems you found in the pressure tubes at Pickering, are they an example of common mode failure?

MR. SNELSON: A. The failures at Pickering, the first one that ruptured, and I forget whether that is Pickering 2 or Pickering 1, and then the subsequent need to take out the second unit because of the same problem, is a common cause failure, yes.

Q. If it turns out that all of the rotors at Darlington have the same cracking problem that the the first one did, I don't know whether you have already solved that or not, I don't know, but if it did, would that be a common cause failure as well?

A. That would be classified as a common cause failure, yes.

Q. Let me take another example.

Suppose that tomorrow morning a government study came down saying the low level radiation for nuclear facilities is a far greater health hazard than anybody ever expected, just hypothetically, and as a result the AECB said, "Hydro, you have got to shut them down for a while, until we figure this out." That would be a common mode failure?

A. I think it is a very, very remote possibility.

Q. Yes, of course.

A. It may be classified as a common cause failure. It is certainly within the concept. I don't know quite how it would be recorded, but...

Q. But in the context of reliability analysis, it would not be, right?

A. I think it is the sort of circumstance that a reliability analysis is not addressing.

MR. TABOREK: A. In the mathematical analysis, it is addressed in another fashion.

Q. Which is?

A. The chance of a common cause failure is dealt with in two ways in setting our reserve margin.

No. 1, it is one of the factors that we

know we do not model, and so that the true analytical minimum total customer cost, if you will, is higher than the minimum total customer cost that we compute using the model. Therefore, it is one of the factors which suggests we should be to the right of the computed analytical minimum total customer cost point.

And the second factor is that our calculations use an emergency interconnection assistance of about 700 megawatts, limited by the amount of interconnection assistance we believe would be available when neighboring utilities and ourselves have made coincident load forecast errors, which it is likely we would do.

And so, in the instance one of the hypotheses you mentioned, tomorrow a large block of generation was gone for a common cause, that would be a common cause, but we would not be in the coincident load forecast error problem, and so that our emergency interconnection assistance would be larger. So, we generally note that that tends to balance a range of common cause failures.

Q. Of course that is going to depend on when the common cause failure occurs, and on how long it is, isn't that right, whether you have the interconnection assistance?

A. That is correct. What you would then postulate are two major failures at the same time, which of course would tend to have a much lower probability than either occurring.

Q. When you use DAFOR, you don't assume that sometimes forced outages will happen when you have lots more interconnection, and sometimes they will happen when you have less interconnection. You make an assumption that you will only have so much when it happens, right?

A. No, I think I have just described to you that we do make assumptions that we'll have different amounts available at different times and different circumstances.

Q. In the F&D model?

A. When we run the F&D model, and we are looking at case of the coincident load forecast error problem, then we use the single number of 700 megawatts.

Q. The reason for that is, if I understand it correctly, that it is not as big a problem to worry about what is going to happen if you have a forced outage in September. The real thing you have to be concerned about in reliability is what about December 15 or January 15.

A. No, you have to really worry about every hour of the year.

Q. The reason you use 700 is because that is the sort of thing you will have when it is a worst case scenario?

MR. SNELSON: A. We don't expect to be limited to 700 megawatts each and every winter peak period.

Q. But you feel that is a safe number to use in determining how much you can rely on from another utility?

A. We don't appropriate.

MR. TABOREK: A. We don't appropriate, let's say.

Q. Okay, appropriate, sorry. Nothing is safe in this, right? It is a cliff.

And the effect of that, if I understand it correctly, is that since you are calculating your reserve margin for winter peak, right? That is where it is driven to?

MR. SNELSON: A. The reserve margin is quoted relative to the winter peak.

MR. TABOREK: A. But it is calculated. It is an annual calculation for the entire year.

Q. I guess I'm just getting a sense that

your answer on common cause failure is that you treat it differently than you would treat DAFOR. DAFOR is uncertain. It could happen at any time, so you have to assume it will happen at the worst possible time. Common cause failure is also uncertain, but you don't assume it will happen at the worst possible time, isn't that right?

MR. SNELSON: A. We assume that DAFORs can occur at any time.

Q. Therefore for planning purposes could occur at the worst possible time?

A. They are given the probability of occurring at the time of peak load.

Q. But you don't do that with common cause failures?

A. We have said that we have not included them in the reliability calculation, because we are not able to define them in probablistic terms. So, they are handled judgmentally in the two ways that Mr. Taborek has explained.

Q. One of those ways assumes that common cause failure doesn't have the same probability as DAFOR of happening at the worst possible time, right?

A. We expect that common cause failures are lower probability events than regular amounts of

DAFORs.

MR. TABOREK: A. I think part of the difficulty here may be that you are confusing two time periods. The one is when you are talking about DAFORs, you are talking about the peak in the year. When we are talking about common cause failure occurring at a time of load forecast error coincidence, it is something that occurs over a period of many, many years.

So, utilities over a period of time, well, over four years is what we are looking at, could make errors that are going in the same direction. So, there are different time periods that can help us sort those out.

Q. Does common cause failure include regulatory restrictions that apply to a number of units? I'm not going to go back to acid gas again. But let's say the AECB came in and said, "We have got a problem with all of your A units, your nuclear A units. Fix it. Now."

That would be a common cause failure, or would it be something else?

MR. SNELSON: A. I think it is not very important in how it is classified. I mean, the effect is that if units are shut down and they are not

available, then it doesn't matter what name you give them.

Q. Well, I'm going to come in a minute to Table 22A on page 30 of the 1990 reliability indices, and you have some estimates of common cause forced outages.

All I'm trying to do, just like with DAFOR, is figure out what the term means before we go to the numbers. So, we know it means a common cause DAFOR, right? We figured out DAFOR is only equipment, and we know that common cause failure at least includes common cause DAFOR, is that right?

THE CHAIRMAN: Didn't Mr. Snelson earlier say that it would if it into the common cause category, that kind of circumstance, but that it never happened, and he considered it remote, sort of, that it ever would happen.

MR. SHEPHARD: I understand that. But they have made some projections for how often it will happen, and all I want to know is what "it" is.

MR. SNELSON: What is in the projection is the things that we think have a significant probability of occurring. The difficulty here is in classifying things that have such a small probability of occurring, that we haven't decided how we would

classify them.

MR. SHEPHARD: Q. So, from the point of view of looking at these numbers then, any non-equipment failures are not included in there.

MR. TABOREK: A. These are equipment failures, and I should mention, we have qualified them earlier, that we don't believe they include all effects, and we don't use these in our calculations.

Q. You, in fact, said the other day that you are -- your words were "not very satisfied"--

A. That is correct.

Q. --with these numbers. Maybe you could expand on that. Why are you not very satisfied?

A. I believe I explained that in my testimony the other day as well. That when you look at our past history, we have experienced forced outage rates higher than forecast, roughly 50 per cent at a time, and a good number of those might be called common cause failure.

Whereas, when you look at these numbers, which are a subset of what might be common cause failures, we get very low numbers. And, therefore, we don't think we have good statistics. Therefore, we have used another approach to judge the impact of this on reserve margin.

Q. I take it then that if these numbers are wrong, your expectation is that they are too low?

A. Yes.

Q. This, as you have said, is only equipment failures. It doesn't include things like disruptions of fuel sources or strikes or anything like that.

A. That is correct.

Q. Maybe you could just describe how this table works for a second. I realize that you think the numbers are too low, and you are not comfortable with them, but let's just see what we've got here so far, okay?

This is nuclear. I'm just picking on nuclear because...

THE CHAIRMAN: What table are we looking at?

MR. SHEPHARD: This is page 30 of the 1990 forecast of reliability indices, which is Exhibit 148. It is Table 22A.

Q. So, where it says here, for example, the possibility of a two-unit outage at Pickering of 170 days plus or minus 50 in a thousand years -- sorry, 170 times plus or minus 50 over a thousand years, and you have a duration in days of four days plus or minus

two, can I just multiple that out and say, your probability is that 680 days out of a thousand years you will have a two-unit common cause failure at Pickering?

...

[12:26 p.m.] MR. TABOREK: A. Yes.

Q. So, that would work out then - and I will just ask you to accept this on faith for now and we can check the numbers later - that would work out to 0.86 per cent probability?

A. I think it would be roughly two in a thousand, in round numbers.

Q. Right, okay, 0.86 is actually more specific, but, yes, two in a thousand.

And then if you went to the upper bound, which is 220 incidents, right, 170 plus 50? At a duration of 6 days, at the absolute upper bound of your range, that would be 1320 days in a thousand years, which would be, let's say, four chances out of a thousand on any given day that you would be out four-tenths of 1 per cent, roughly.

If you look at the lower bound, it is actually less than one-tenth of 1 per cent probability that you would have a two-unit. Now, are these cumulative? You have two-unit, four-unit, and eight-unit outages, so are they cumulative in the sense that you could add them all together to get a probability of any common cause outage at Pickering?

A. I don't know the answer to that.

Q. I wonder if you could just provide

us, undertake to provide us with the relevant percentages of probability, like DAFOR, sort of a common cause outage factor - we will have to create a new acronym for it - for these various projections on ths chart? Could you do that?

A. Yes.

Q. That would be 54, is that right, 142.54?

MRS. FORMUSA: 55.

THE CHAIRMAN: 55.

MR. SHEPHERD: 142.55.

Q. Now you said in that report - I won't go to it - but you said in that report, the common mode outage forecast is based on actual station experience plus the judgment of Ontario Hydro experts.

MR. TABOREK: A. Yes.

Q. Was a study done of some sort or a specific data analysis?

A. No.

Q. I mean it wasn't just somebody sitting down and saying, "Well, let's use 170"? It was more sophisticated than that?

A. I think some rudimentary calculations would have been done, but I would not call it an analysis.

Q. Okay. Now, when you are looking at the past history, of course, you are including things like pressure tubes; right?

A. Yes.

Q. And this is the reason why you are not satisfied with the numbers: that if you look at things like pressure tubes, they tend to be longer and more of a problem than this suggests? Did I understand that right?

A. I have described my rationale for dissatisfaction, yes, and that's one of them.

Q. Is it fair to say that where a system relies heavily on a particular technology, a particular design or a particular technology, that the likelihood of common mode failure increases?

A. I think the answer is, to a degree, yes and, to a degree, no. There are utilities that are one hundred per cent hydraulic, there are utilities that are one hundred per cent coal. It depends on the particulars of the hydraulic units and the particulars of the coal units. And so I cannot give you an across-the-board answer to it. But in some instances, if there are common elements right across the system, then yes.

Q. Is it also fair to say that the

younger the technology is that you are using, all other things being equal, there is probably a higher probability of common mode failure?

A. No. If we use a lot of combustion turbines, for instance, that would not necessarily lead us into a large amount of common mode failure. You would have to look at the characteristics of that technology.

Q. So, you don't think that a mature, more well-known technology is less likely to have common mode failure?

A. The most mature technology is, I believe, the hydraulic system -- no, I guess. No, I don't. The new technology is going to have more teething problems. It doesn't necessarily mean there are going to be common mode failures because there are three types of problems that can occur: teething problems, the mature, and the wear. And in the mature and the wear, they occur after a period of time and common modes can be in any one, so no.

Q. Will common mode failures generally be more likely related to design than to operations, all other things being equal?

A. I think you described a -- I can't answer that.

Q. You don't know whether --

A. There is just not enough information. It is just too hypothetical a statement to respond to. There is just no information there other than design and operation.

Q. All right. Is it true that as your generation system relies more heavily on a particular technology, the impact of a common mode failure affecting that technology increases, it's worse?

A. Well, again, I think I answered this just a few questions previously. If we had a one hundred per cent coal system, it is unlikely that each and every generator, for instance, on that system would be absolutely identical, and therefore maybe all the generators of manufacturer "X" might experience a common mode failure, but that doesn't mean that all the generators on the system are manufacturer "X"s, even though it is all the same technology for instance.

Q. I will just give you a sort of hypothetical and we will see whether we can get there from there.

Let's suppose your entire system is identical to Pickering "A" units with whatever they were, zirconian, whatever they were, pressure tubes.

A. Clones.

Q. Pardon?

A. We have clones. We have a system made up entirely of clones.

Q. Exactly.

A. Is that what you are referring to?

Q. All right.

A. Yes. And that --

Q. The pressure tube in Pickering 1 breaks.

A. In that hypothetical but unrealistic case because no utility would do that.

Q. Okay. But if you had all Pickering "A"s throughout the system --

A. Yes, certainly.

Q. That would be a lot more serious than it was when it happened; right?

A. Yes, certainly.

Q. Isn't it true that the more Pickering "A"s you have relative to the size of the system, the more serious a common mode failure in that type of unit would be.

A. In that hypothetical example, yes.

Q. I am not asking about the hypothetical now. I am saying you have got the hypothetical over here, you have what happened there --

A. Then I go back to my answer with respect to real systems.

Q. All right.

Let me ask, Mr. Snelson, you talked about the other day, I don't know remember, I think it was Wednesday or Thursday, you talked about the fact that coal piles can freeze under certain winter conditions and the result might be you would have deratings of several units; right?

MR. SNELSON: A. Yes.

Q. Just as an aside. If that happened would that be included in DAFOR?

A. Yes, I believe so.

MR. BARRIE: A. Yes.

Q. But it would not be for the reliability indices, is that right? When you are doing your calculations, it would not be?

MR. SNELSON: A. I believe that would be in the reliability indices.

MR. TABOREK: A. And I think we properly should take it out. So, we are perhaps over stating DAFOR. I think we would fix --

MR. SNELSON: A. You can consider it to be a failure of the coal handling equipment.

Q. All right.

MR. BARRIE: A. Let's put the thing in perspective here. We operate our coal piles such that we do not suffer a great deal of deratings because of this phenomenon.

Q. Now, what causes them to freeze. Maybe you can just briefly describe that.

A. Cold weather. (laughter)

Q. No, I realize it's cold weather, but is it a particular combination of precipitation and cold or is it a combination of the size of it and the cold, or is it just if it's too cold it freezes.

A. Well, to be honest, the major problem we have with coal piles is not so much particularly cold weather causing freezing because one tends to just scrape the top of and the coal underneath is normally okay, so that's why I wanted to say right away that this is not a major problem.

However, we do have problems with handling coal piles. Often if it is extremely wet, that can actually be a bigger problem than actually freezing coal piles.

Q. Would it be fair to say that if you had one of those weather-related coal pile problems at Lambton, there is a good possibility that you would have a similar problem at Nanticoke?

A. Given that Nanticoke and Lambton aren't too far apart, they could well both experience wet conditions at the same time.

Q. But now I am getting back to definitions again. That would not be a common mode failure, would it, common cause failure?

A. Operationally we don't go to great lengths to define common mode failure.

Q. That is not the type of thing that you, Mr. Taborek, have included in your analysis?

MR. TABOREK: A. No.

Q. I was going to ask about zebra mussels and common cause failure, but I just can't bring myself to do it. (laughter)

Let's go to service lives. Could you turn to interrogatory -- now this one is out of order, I think. It is in Interrogatory 2.9.7, which I thought was in this pile.

THE CHAIRMAN: Can we have the number again, please.

MR. SHEPHERD: It is 2.9.7, Mr. Chairman. It should be in here. It is not in my pile. Does anybody have it in their pile.

---Off the record discussion.

MRS. FORMUSA: I have it. I put it

together, so...

MR. SHEPHERD: I see. So, the witnesses have it, but nobody else does.

Let's see if we can get by without it, okay, let's see if we can get by without it.

Q. You made the point there, and you have actually made the point in the transcript as well I believe, that the planning life, the service life you use for planning and the real life aren't the same thing; right? That is, just because you use a 40-year planning life doesn't mean that in fact on the fortieth birthday, you are just going to shut the thing off.

MR. TABOREK: A. It is the most likely life. You're right it is not necessarily the same.

At the present time, although you're planning a 40-year life for fossil units, you don't currently have scheduled the closure of any fossil units, do you, scheduled in the sense that you have decided when such and such day comes, we are going to close it?

...

[12:40 p.m.] A. That is correct.

Q. I have never actually heard of an Ontario Hydro fossil unit being closed. I guess, what, they just haven't gotten old enough to close them yet?

A. Actually, one of the earliest units we have on our system in the early days of Hydro was a fossil unit, and it was closed.

Q. That's Keith?

A. No.

MR. SNELSON: A. Scarborough Generating Station.

MR. TABOREK: A. Scarborough Generating Station.

Q. Scarborough Generating Station. My records didn't go back that far.

Anyway, that's closed and you don't use it anymore.

A. That's correct.

Q. There's a park or something there, right?

A. I am told it's under Hearn somewhere.

Q. All right.

A. I don't know its age when it closed.

Q. You have two though, Hearn and Keith, that are mothballed, right?

A. Yes.

Q. And you currently have plans to -- let me come back to the plans in a second.

You had some discussions the other day with Mr. Watson, I think, about a possibility that you could actually run units like Hearn and Keith, for example, or any of the other ones, far beyond their 40-year life if you repowered them or rehabilitated them in some way. There is a lot of opportunity to extend, isn't there, if you are willing to spend the money.

A. No, I don't think I said that.

Q. Okay. I got the impression that you had a fair bit of flexibility based on your economic decision at year 35 or 40, or whenever.

A. What I said was that you might then be able to, and then you might extend. But I didn't -- what was the word you used? The implication that there were plenteous opportunities?

Q. I said a fairer degree of flexibility.

All I am really getting at, it's an economic decision at that point, right?

A. No. There are four factors which I outlined in my direct. The equipment condition, the

economic considerations compared to new technology, the environmental considerations, and the availabilty of new options.

Q. Okay. Nuclear is different in that respect, though isn't it? That is, when you get to the end of the life of a nuclear station, you don't have the same four options, the same four factors, do you?

A. I think you do.

Q. Isn't it true that at a certain point in time everything in the nuclear station becomes too radioactive to use it anymore for power production, even the containment unit, in fact? Isn't that just a fact of physics?

A. Not that I am aware of. And it's certainly not going to happen before the 40 years. I must say, I am not an expert. You may wish to pursue this with the nuclear panel, which is 9.

MR. SNELSON: A. It's Panel 9. And the operation of the tritium removal facility to detritiate heavy water is one way of reducing the radioactive levels, levels of radioactivity in an operating station over a period of time.

Q. Could you take a look at Interrogatory 2.7.50. Unfortunately, again in this interrogatory, the pages are not numbered. I am going

to ask you to go to the sixth last page of the interrogatory. That page says at the top --

MR. TABOREK: A. We only received the four cover sheets. Is that what you are referring to?

Sorry, sixth last.

Q. There is a copy there.

MR. BARRIE: A. I think we have got it. What was the page?

Q. The sixth last page it says, on the upper right-hand corner it says "1980 DRC Extract."

MR. TABOREK: A. Yes.

Q. Okay. And that says, nuclear generating stations are designed to operate for 30 years; right?

A. Yes.

Q. And it says, let's use a 30-year assumption of service life; right?

A. Yes.

Q. And could you then turn six more pages towards the front, and this page is headed up "1981 DRC Extract."

A. Yes.

Q. This is the point at which Hydro decided to change the service life assumption from 30 years to 40 years; is that correct?

A. Yes.

Q. And it was based on an analysis that took place during that year; is that right?

A. Well, I was not on the DRC at the time, but yes, analyses would have been going on over a period of time, and I would believe the DRC at that point would have felt sufficient evidence was available to effect a change.

Q. Well, you are on the DRC now?

A. Yes.

Q. And every year you have to decide what service life to use for nuclear; isn't that right?

A. Yes.

Q. So, presumably, you have to go back every year and review the basis on which you using 40 years now?

A. Yes.

Q. And I am asking you then, what is the basis on which you are using 40 years now?

A. The basis is that the DRC moved to that in 1981 for 1982.

Q. Well, I don't think that's the basis, maybe it's just my semantics.

A. And that we have revisited the decision every year since then and we see no reason to

change.

Q. So, each year when you look at the 40 years, you don't say, there was this study or this piece of work done that justifies 40 years and it is still valid?

A. What you have is an accumulation of knowledge over time that permits you to check whether in the light of what you know now, which will certainly be different than what you knew in 1981, the 40-year life is valid. So, for instance, one of the things that in '80 the reference was to nuclear stations being designed for a 30-year life, "B" stations are designed for a 40-year life. The fact that components have 40-year lives, for instance, is relevant.

Q. So, each year when the Depreciation Review Committee sits down and does this, you don't go back to square one; you just say, "Did anything happen in the last year to make us change this"?

A. What you do is you review all that you consider to be relevant to the decision you are making.

Q. Well, I am trying to get a category of what sorts of things you consider relevant to the decision you make and I don't think you have told me yet.

Is my example right?

A. All of the things are relevant.

No, we do not go back and dig out the 1981 files and read them. We do, however, have people contributing to that judgment who are aware of what was done in the various years.

Q. Now, if you just take a look at the bottom of that page, the recommended remaining life you have for obviously for Pickering and Bruce and you also have for NPD, Nuclear Power Demonstator, which is the small unit at Rolphton, right, and also Douglas Point?

A. Yes.

Q. And these would have the NPD going out of service, that's the Nuclear Power Demonstator, going out of service in 1998, if I do my calculations correctly, and Douglas Point going out of service in 2008; right? Just do the numbers from '81, add those 27 years, you get 2008.

A. Yes.

Q. Isn't it true that if you go through this, and I will ask you to check to make sure this is true, that up to and including the '84 Depreciation Review Committee Report, those numbers remained; that is, those numbers of years remained for NPD and Douglas Point?

A. Subject to checking, yes.

Q. But they are not still in operation now?

A. That's correct.

Q. When were they closed? If I said Douglas Point was '84 and NPD was '87 --

A. In the mid-80s, I would have answered.

What were the years?

Q. Douglas Point was '84 and Rolphton was '87, that's NPD was '87?

A. That sounds about right.

Q. So, in 1984, then, the Depreciation Review Committee would be saying, assume another 24 years, I guess, for Douglas Point, and then within the year it was closed.

A. Yes.

Q. Do you have any idea why that is? Were they just wrong or had somebody already made a decision that they didn't know about?

They didn't even last their original design life, did they?

MR. SNELSON: A. Both of these facilities were owned and operated by Atomic Energy of Canada Limited. Now, both dwere somewhat in the nature

of prototype facilities. The NPD was a very small prototype, the sort of smallest prototype that could produce a useful amount of power.

Q. It was 250 megawatts?

A. No. NPD was about 20 megawatts --

Q. Sorry, 20.

A. Forty megawatts. Quite small. Douglas Point was 200 megawatts.

Q. Okay.

A. My understanding of the circumstances surrounding the Douglas Point retirement was that Atomic Energy of Canada essentially made that decision, in that, they decided that they no longer wanted to continue operating the station.

Q. So, it had nothing to do whether you could have operated it longer; AECL decided that they didn't want to have it operated any longer?

A. They were getting certain revenues for the electricity that was produced from the plant and they were probably facing some repair costs and they decided that they didn't wish to continue operation.

Q. Is it true that Hydro is alone among all the nuclear utilities in the world in assuming a 40-year life for nuclear?

MR. TABOREK: A. I don't know the answer to that. I am not aware of other utilities who also assume 40 years.

Q. Well, you are on the Depreciation Review Committee, presumably one of the things you look at is what other utilities do.

A. Yes.

Q. You have never seen another utility uses 40 years?

A. No.

Q. Have you seen lots of utilities that use 25, 30 and 35 years?

A. Yes.

Q. Now, you actually have no experience with aging nuclear stations, do you, that is Ontario Hydro?

A. We have a lot of experience with aging nuclear stations, with 20 units.

Q. Well, okay. You said at page 2865 of the transcript, which is in Volume 16, I will read it to you:

"There is little or no experience with the operation of modern, high pressure fossil plants and nuclear plants for long periods of time. We basically don't know

that they can be economically maintained
for more than 40 years."

A. Yes.

Q. Now, your oldest nuclear facility is 20 years old; right?

A. Twenty-one, yes.

Q. So, is it fair to say that, in fact, not only do you not know whether they can be run economically over 40 years, but you don't know whether they can be run economically over 30 years or over 25 years; is that right?

A. You are putting "know" in the sense of an absolute guarantee. We believe, and the information we have suggests, that that is a reasonable life for those units and that that is the life that we would get from them.

Q. But that's not based on experience, either yours or anybody elses?

A. No, clearly not. When you only have 21 years of use in your oldest, you clearly don't have the 22 to 39 years of experience.

Q. And nobody else in the world has any that are older; do they?

A. Not with CANDU.

Q. Well, even with other ones. Isn't

the oldest nuclear facility in the world now 23 or 24 years old; isn't that right? About right. Certainly not 40 years.

A. I think that's probably correct. I don't know the answer to that. I think you could address that to Panel 9.

Q. So, you have a forecast that is not based on direct experience?

A. That's correct. Most forecasts have to be that way.

Q. Well, if you are forecasting the life of a hydraulic facility, you have, what, 150 years around the world of experience with hydraulic facilities? It's pretty different.

A. Well, not with our types of hydraulic facilities. The load forecast, we have no experience with the loads in the year 2000.

...

[12:56 p.m.] Q. Fair enough.

A. That is why it has to be a forecast.

Q. So, you have a forecast that is not based on experience and is out of step with everybody else's in the world, right?

A. Not necessarily. One of the reasons that utilities in the U.S. use -- set their lives is that they are quite often associated with the licences that are given for the unit, rather than an appraisal of what the life actually is. And in the U.S., there is considerable emphasis now on extending the lives of nuclear plants over their present licence lives.

Q. So, if we were to compare the various service life assumptions of utilities and regulators and others in the United States, as against, let's say, Britain, before the privatization there, or France, or any of the European countries that have nuclear, we would find that in the United States, they use lower lives, generally. Is that the import of what you are saying?

A. If you wish to go into a detailed country-by-country comparison of lives, I would refer you to Panel 9.

Q. Well, is it the nuclear people who set the life for...

A. We set the life.

Q. You sit on the committee.

A. Yes.

Q. But you don't want to talk about it.

MR. SNELSON: A. There are nuclear people who sit on...

MR. TABOREK: A. There are nuclear people who are also on the committee.

MR. SNELSON: A. Who bring the specific knowledge and nuclear technology to the committee.

MR. TABOREK: A. We bring the system needs to the committee.

MR. SHEPHARD: Mr. Chairman, this might be an appropriate time to have lunch, if that is convenient.

THE CHAIRMAN: You are satisfied with those answers?

MR. SHEPHARD: I have been sort of dissatisfied for the last hour, but I think I've got what I can get.

THE CHAIRMAN: We will adjourn until 2:30.

---Luncheon recess at 12:59 p.m.

---On resuming at 2:33 p.m.

MR. SHEPHARD: Mr. Chairman, at the

current rate, it looks like this cross-examination by IPPSO will be completed sometime mid-morning on Monday.

Q. For some reason, I skipped a question earlier that I hadn't meant to skip, so I'm going to go back to it, if you don't mind.

Can you just give us a brief description of the current in-service problems with Darlington, the current status of it?

THE CHAIRMAN: I am sorry, I didn't hear that.

MR. SHEPHARD: Q. The current in-service problems at Darlington. There have been some delays. Could you just give us the current status?

MR. BARRIE: A. We just did that. We did that two days ago. Do you want me to repeat it?

Q. I am sorry, I thought I read the transcripts fairly carefully. I didn't see it; maybe I missed it. Maybe you could just summarize it briefly, so I could...

A. Both Darlington Unit 1 and Unit 2 are not operating at the moment.

Q. Yes.

A. The problem with Unit 2 is a problem with the fueling machine and associated damage to the fuel bundles. The precise cause of it hasn't been

established yet, but that is the nature of the problem.

Unit 1 has been taken off for examination, to see if similar problems exist, and at this point in time, it appears that there is some problem on Unit 1. There is no actual broken fuel bundles as such, but there is some evidence that there has been some stress, some scraping.

The net result of this is that it is expected that Unit 1 will be on sometime during the summer for some tests, but will have to come off again. And both Unit 2 and Unit 1 will not be back in-service properly until November of this year.

Q. So, the earlier cracked rotor problems, you have now concluded that they are solved?

A. No, that is still under investigation.

THE CHAIRMAN: So, that is an additional problem to the ones you have already mentioned.

MR. BARRIE: Yes.

MR. SHEPHARD: Q. The cracked rotor problem, if I understand that correctly - and maybe you can just correct me if I'm wrong - this rotor is sort of like the driveshaft; is that right?

MR. BARRIE: A. Let's make this distinction right away. It has nothing to do with the

nuclear end of the generating station.

Q. No, I understand.

A. It is at the alternator.

Q. Yes.

A. It is that which is actually producing electricity. So, it is the turbo alternator, the shaft of the turbo alternator.

Q. And this shaft is, I understand, something like three metres in diameter; is that right? It is big.

A. I don't know.

Q. Does anybody have any idea? Are we talking about something of very large size?

A. You'd be measuring it in metres, single metres, if that is close enough for you. But I don't know if it is three metres, two metres or four metres.

Q. Am I right in understanding that you used a new design for Darlington, in which you used a hollow shaft rather than a solid shaft?

A. You are getting beyond my level of expertise. I don't know.

Q. There is nobody on the panel that knows anything about that?

MR. SNELSON: A. People on panel 9 would

be the nuclear experts, and they will have much more detail.

Q. Now, related to that, then, the F&D model, as I understand your evidence, Mr. Snelson, has an uncertainty associated with in-service date of six months before and twelve months after, is that correct?

A. That is correct.

Q. Of course, Darlington is well beyond that, right?

A. Darlington, some of the Darlington units are well beyond that, yes.

Q. The first two, two in one with the problems are already substantially beyond that.

A. Yes. Our experience in four-unit generating stations has been that we tend to be more susceptible to delays and in-service dates on the first and second units in the station than the third and fourth units.

Q. In other words, if I'm right, you are likely to have more teething problems with the first ones you bring on?

A. Yes. When you are bringing four essentially identical units into service, then you tend to discover any problems on the first unit, and to a lesser extent on the second. By the time you are ready

to commission the third and fourth units, then you usually have got the problems fixed on the first and second units, and you know what to do to fix the problems, or to prevent them occurring on Units 3 and 4.

Q. Of course, Units 3 and 4 at Darlington, their current planned in-service dates, if I'm not mistaken, are still much later than you had expected, say, two years ago, three years ago, is that true?

A. I would have to check that. There has been some slippage, I believe. I couldn't give you the chapter and verse on the amount of slippage.

MR. TABOREK: A. Information on slippage of nuclear unit in-service dates is contained in Exhibit 87. There is a table in there that provides that information.

Q. Oh, good. Now, when we are talking about the uncertainty in in-service dates. You are talking about the F&D model, right?

What about the LMSTM model? Does it have any uncertainty in in-service dates in it?

A. I believe one of the, one of the requirements of the LMSTM model is that all the units be brought into service on January the 1st of a given

year. And that it doesn't have any facility to bring units into service gradually. They come in on January the 1st of the year.

Q. Do I take it your answer to my question is no?

A. Our practice is to generally plan units to be in-service somewhere towards the middle or the end of the year, say August to October time period, so that they will be in service before the winter peak, which normally occurs December, January or February following.

The structure of the LMSTM model requires that the units be put into service on January the 1st of a year. So, we will show them in the LMSTM model on January 1st of the -- that usually follows their actual planned in-service date. So, that will inherently have some degree of lateness accounted for. But it is part...

Q. Two or three months?

A. Two or three months. It is largely driven by the structure of the model.

Q. Do you have any idea when the last time was that you brought a unit, fossil or nuclear, in-service within two or three months after its planned in-service date?

A. I can't give you the precise dates, but there are cases of units coming into service ahead of their planned in-service dates.

Exhibit 87, the table lists the in-service dates of units.

Q. So, it has a whole summary of it there?

A. Yes.

Q. Excellent, thank you.

I understand you plan to demothball the Hearn and Keith generating stations, is that correct?

MR. BARRIE: A. Current plans do not include demothballing Hearn or Keith.

Q. Okay. I am sorry. I'm going to leave that.

So, you have no plans right now, am I clear, you have no plans right now to demothball Hearn or Keith?

A. That is correct.

MR. SNELSON: A. From a planning perspective, the situation remains as it is described in the Demand/Supply Plan, that under median load growth, we would not expect to have to use Hearn or Keith.

Q. Correct me if I am wrong, I was

understand the impression that you had, at least, at some time last year, a plan to have Hearn up and running on December 1st, 1991, and in fact, there was quite a controversy about that at the OEB. Am I wrong?

MR. BARRIE: A. No, that is correct. There was a plan to demothball two units at Hearn.

Q. Yes.

A. That plan was changed, really, when the load just fell away, and we reassessed the situation and decided that it was no longer required. And our analysis for this next winter and the next five winters are that we would not require to restart Hearn or Keith.

Q. Is it fair to assume that with Darlington coming on stream over the next few years, the short-term problem that you had, that you intended to address, would be a problem later, and you'd have Darlington, so you wouldn't need it? Is that right?

I know that wasn't a very eloquent question. I am sorry.

Before Darlington, you could have a possibility of a shortfall under the old load forecast, but the new load forecast doesn't show the shortfall.

A. The reason we were bringing back Hearn, because we were still expecting, in enough time,

significant load growth, and we were at that time also experiencing delays with Darlington. The combination of those two things were major factors in the initial decision to bring back two units at Hearn.

Now that the load growth has been radically reduced, at least in the short-term, in the next two or three years, that need evaporated.

Q. So, at present, they are just sitting there. You have no plans to do anything with them, is that right?

A. No, they are not just sitting there. No, two units in particular at Hearn are playing a very useful role in power system operation. They are not producing any megawatts, but we use them as what we call synchronous condensers that help support the voltage in downtown Toronto.

We have a problem maintaining adequate voltage levels in Toronto, and we are using two units at Hearn to help support the voltage levels. They are not producing any megawatts, no power.

Q. Your voltage problem in Toronto is because of the size of the load, relative to the local generation, is that right, essentially?

A. The voltage problems in Toronto are because we have heavy flows of power into the Toronto

area, and we have inadequate resources to maintain voltage levels.

If you did have local generation, yes, that does help to support voltage. There are other ways of supporting the voltage, as well, though.

Q. For example, if you restarted Hearn as a generating facility, that would also solve the problem, wouldn't it?

A. That would help to maintain the voltage levels, yes.

Q. Isn't it true that private sector companies have approached Hydro and offered to acquire Hearn and Keith and redevelop them using newer technologies?

MR. SNELSON: A. I believe there have been proposals with respect to both sides, yes.

Q. And isn't it true that in the case of Hearn, the proposal was for a thousand megawatts of gas cogeneration?

A. I'm not sure that it is appropriate to discuss the specific non-utility generation proposals. This really is a matter for Panel 5, and those proposals would have come in through our non-utility generation division, and they would be familiar with the details of those proposals.

Q. If I were to ask you about the proposals on Keith, you would give me the same answer presumably?

A. Yes.

...

[2:46 p.m.] Q. At present, do I understand correctly that Hydro does not have any intention to proceed with any such proposals?

A. I suggest you direct that to Panel 5.

Q. You don't know the answer to that?

A. I know part of the answer but I don't know the whole of the answer and I think you will get a better and more authoritative answer from Panel 5.

Q. Okay. That's the end of the questions on operational issues. I want to shift now to environmental issues, although some of them have operational issues associated with them.

Let me start with acid gas.

Ms. Ryan, earlier in this cross-examination, there was some discussion of the limits on economic dispatch associated with acid gas. And I take it - I am not sure that I have got this exactly right - but I take it that sometimes, perhaps even often, Ontario Hydro has to use more expensive generation rather than less in order to keep within its acid gas limits; is that true.

MS. RYAN: A. As described by Mr. Barrie, that is true, and Mr. Barrie would be better to answer with respect to how we load our units.

Q. It is just a set-up question. I was

just tying it back into the old stuff.

And am I right in assuming that if you have less hydraulic generation in a year, because of low water or because of outages or whatever, that will tend to increase your difficulty with meeting your acid gas limits?

A. Depending on load requirements of the year, we might have to run more fossil.

Q. All other things being equal, less hydraulic which will generally mean more fossil and, therefore, more acid gas problems, is that right, all other things being equal?

A. More fossil, yes. I don't agree with your more acid gas problems.

Q. Sorry. More fossil then will typically make it tougher to meet the acid gas limits. I am not suggesting you wouldn't meet them, simply that the more you have to use fossil, the tougher it is; isn't that right?

A. The more we use fossil, the more acid gas emissions, yes.

MR. TABOREK: A. Our whole program is developed around the recognition that our fossil generation requirements can vary substantially, and so we prepare from the outset to handle variations.

Q. If you don't get a new hydraulic facility built or rehabilitated when you hope, can I take it that, at least for a while, that is going to increase the pressure on meeting your acid gas limits?

Say you had planned to have one rehabilitated with an extra few hundred megawatts in '94, and something happens and you can't, does that mean you have more pressure on your acid gas limits?

MR. BARRIE: A. Any reduction in hydraulic or nuclear output will tend towards causing more fossil production and thereby causing more emissions of acid gas.

Q. Now the Demand/Supply Plan has several thousands megawatts, 2,000, 3,000 megawatts of new hydraulic in it. I assume that if that is not approved, then at least in the short term, before you can get more nuclear on, you have got a pretty serious acid gas process; is that right?

MR. SNELSON: A. You would need more acid gas control measures.

Q. Okay. You would have to involve scrubbers, say, or selective catalytic reduction systems, something like that?

MR. TABOREK: A. I mentioned we made provision to accommodate variations, and you illustrate

one example that would cause a variation. And one of the responses we put in place for that is we received a blanket environmental approval to fit up to 20 scrubbers on our main coal-fired plants. And by having this blanket approval, what we have done is reduced the lead time for the installation of scrubbers from approximately 7 years to 4 years.

And so, in the case you mention of a hydraulic station not coming on, we would have four years' lead time. If we knew that four years in advance, we would put a scrubber on. Well, we would go through a set of analyses and a scrubber would be one of the options.

If we had less lead time than that, we would alter the sulphur content of our coal. And if we had less lead time than that, we would use our energy margin.

THE CHAIRMAN: You would use what, I'm sorry?

MR. TABOREK: Our energy margin. We have referred to a 9 terawatthour energy margin that we use in our planning.

And then we would go on. We have, I mentioned -- there, I guess, I have listed three or four options, but we have perhaps half a dozen or a

dozen options at various times in order of cost that we would use to meet the emission limits should the coal burns vary.

MR. SHEPHERD: Q. To be fair. You would have the same problem if your demand side management and NUG programs didn't produce the numbers you expected either, wouldn't you?

MR. TABOREK: A. Yes.

Q. You would have to take the same sorts of action?

A. Yes, that's another source of variation.

Q. It sounds likes coal in at least the next ten years is the swing fuel. If these other things don't happen, coal is the --

A. Near enough. Gas and oil would begin to be on the margin but, yes, for your purpose you are generally right.

Q. Now, Mr. Barrie, last week you said that the major reason that you had acid gas limit problems in 1990 was poor performance from nuclear units; is that right?

MR. BARRIE: A. That's correct.

Q. And it is generally true that poor nuclear performance will, as a side effect, put

pressure on your acid gas control program, generally?

A. Less nuclear means more fossil and means more acid gas emissions.

MR. TABOREK: A. I think I would like to say that nuclear was certainly a problem. But we had just come through five or six years of load growth, more than doubling our forecast, and that is cumulative effect over the period. So, there were two factors and our program handled both.

Q. Yes, I understand that. I am going to get to that in a second.

I guess I am right then in assuming that the delays in the Darlington in-service date are also causing acid gas problems?

MR. BARRIE: A. Yes.

Q. I should not say causing acid gas problems. Increasing the pressure on you in dealing with your acid gas limits.

A. Yes, the delay at Darlington we now projected an increased fossil burn of about 5 terawatthours. Sorry, take that back. The reduction in Darlington is about a 5 terawatthour reduction in the electricity that we expected from nuclear units. That would have to be made up.

Q. That's for 1991?

A. Yes.

Q. Now, in 1990, you had to purchase a fair bit to cover acid gas problems. Does that indicate that you are going to have a similar situation in '91? You may have to do some purchases?

A. No. Our projection right now is that even taking account of the delay at Darlington, our present projection is that we should be coming in around 210 gigagrams compared to a limit of 280.

Q. Why is your number this year so much lower than last year? It's a fair difference; isn't it?

A. It is.

Q. You have no more nuclear or--

A. We do.

Q. --hydraulic on.

A. We expect more nuclear in 1991 than the units that we got in 1990. I'll give you the numbers if you wish.

Q. Oh, that's right because two Darlington units will be in-service in November, and December?

A. We have had some Darlington units already. We expect some more. But that we are also expecting more from Bruce than we got in 1990 and from

Pickering.

Q. I don't think we need the details. I think we have got the general gist of that.

MR. SNELSON: A. There is another factor, and that is that, in 1990, we expected to be in a fairly tight situation from acid gas, because it was the first year at which the regulation had been lowered. '86 to '89 was a constant level and then it was lowered significantly in 1990.

And we started a process of making a significant change in the sulphur content of the fuel by going to low sulphur coal, even lower than we had gone to in previous years and adding flue gas conditioning to enable precipitators to work on the new lower sulphur coal. And we had some teething problems with that system in 1990, and it is working a lot better in 1991.

Q. Isn't it also true that Ontario is right now in a middle of a recession and, as a result with less economic activity, you have less load than you expected?

MR. BARRIE: A. Less load, yes. That is assisting us in meeting the acid gas, yes.

Q. Is that sort of a minor aspect of it or is that a major impact on your ability to meet the

limit this year, do you think?

A. It is a contributory factor. I am trying to make a comparison between 1990 and 1991 because that was the gist of your question.

Q. Yes.

A. So, although the load increase has been drastically reduced, the year-on-year difference between '90 and '91 in terms of the total terawatthours that we expect to deliver is not all that great.

Q. Yes. Do you have any sense of whether, but for the recession, you would still have been able with the same measures to have met your acid gas limit this year?

A. I'm confident we could have, yes.

MR. SNELSON: A. There is another aspect of load forecast uncertainty. While the load this year is less than we would have predicted it to be perhaps a year or more ago, before the recession, it is probably higher than it was forecast to be three or four years ago, when we were making some decisions about acid gas planning for 1991.

So, we had high load growth in '87, '88, '89. And then load growth dropped off in 1990 and 1991, but we are still above the load that we were predicting in the mid-1980s.

Q. 1990 was a year when your limit dropped too; right?

A. Yes.

Q. So, it made it even more difficult presumably.

A. I am just saying that we are talking about load being lower than predicted, and you always have to keep it in relationship to which year's prediction.

Q. Yes.

A. So we are lower than we were before the recession started. We are lower than we predicted we would be before the recession started, immediately before the recession started. But we are higher than we predicted we would be at a time when we were not anticipating the strong growth in load and economic growth that occurred through the mid- to late 1980s.

Q. You went up faster than you expected and then you went down when you didn't expect it, but where you are now is actually higher than where you expected to be in the first place?

A. Yes.

Q. That's fair.

Now, this may seem obvious, but if you have further Darlington delays, presumably, that is

going to put some pressure on you this year and subsequently until it comes onstream; is that correct?

MR. BARRIE: A. We have only studied 1991 in any detail. We have postulated the possibility that we won't get any more Darlington in 1991, and we have examined the situation to see what it would be specifically with acid gas. And we will be comfortably within the limit, even if we don't get any more generation from Darlington this year.

Q. And that's with no purchases?

A. That's with no purchase.

Q. You don't have any contingency plan in place to deal with the possibility that Darlington might be off for two or three years before you get it?

A. I haven't done the analysis, so I can't tell you exactly what the numbers would be. I don't believe we have a specific contingency plan that looks at a delay of more than what I have indicated.

Q. Now at the end of the year, if you are close to your acid gas limit, if I am not mistaken, you keep within them by either burning light oil or natural gas or by purchases from other utilities? If you are getting close to the top.

A. It is an ongoing process throughout the year. I wouldn't like to just focus on the end of

the year. We are looking at an annual emission limit.

So, we have a plan which looks at the whole 12 months. In fact, what we did was we made purchases right at the beginning of 1990 in an attempt not to get into the kind of situation that you described earlier, where you are very close to the limit.

...

[3:00 p.m.] So, we will use those measures I described throughout the year. We are aiming to come in below the legal limit.

Q. Now, when you purchase from other utilities on that sort of basis, is that generally more expensive than burning coal yourself?

A. Buying that amount of electricity as we did, yes, it was more expensive than our own coal-fired plant.

Q. And am I right in assuming that some of those other utilities, maybe most of those other utilities, often use unscrubbed coal for their generation?

A. The purchases we made were from a variety of sources, and certainly unscrubbed coal would be one of them.

I did provide on analysis, or a breakdown, of the purchases we made, in a response to an interrogatory.

Q. I have it. We will get to it in just a second. But I guess first, is it true that acid gas emissions from nearby utilities often have negative environmental consequences in Ontario? We talked the other day about deposition and that sort of thing.

A. I think I said at that time I am not

an environmental expert, but yes, the prevailing winds are in this general direction so, I would expect some of it to be deposited. But I don't know how much.

Q. But it's clear from your previous evidence, I take it, that we do include any imputed acid gas emissions from the generation we purchase from other jurisdictions, you don't include it in Ontario Hydro's numbers?

A. We don't, and we don't claim credit when we displace theirs either.

MS. RYAN: A. I think it is important to point out that when we purchase power, the utilities from which we are purchasing also have regulatory requirements, and are, in fact, meeting those requirements.

It's true to say that there has been a discrepancy in the regulation, Ontario's regulations caused to us step down first, but the at the end of last year the United States passed the U.S. Clean Air Act amendments, which require American utilities to step down their emissions by 10,000 tons, American tons by the year -- sorry, 10-million. And so, what we have seen is a discrepancy for a short period of time.

But because, as you have indicated, pollution is an international problem, there are

international agreements being struck to try to rectify that. In fact, in March of this year, there was a U.S./Canada Clean Air agreement signed between our government and the American government to try and bring the regulations more into line.

Q. So, does that mean, then, that in the future, if you get into an acid gas problem, you can't buy?

A. From what perspective, that it wouldn't be able or the law would prevent it?

Q. Yes. Again, consider my hypothetical December situation, and I understand that you don't anticipate that, but consider it.

MR. TABOREK: A. I think the answer is no, because the American utilities will take steps to obey their law, and in obeying their law, there will a surplus at times, as there is now with the present laws. And that we will buy from them and we will sell to them from our respective surpluses.

Q. So, even if they are regulated, assuming that they are still within their limit, your purchase is going to result in more total acid gas emissions; isn't that correct?

A. Yes. Well, total...

MR. SNELSON: A. If their regulation

requires a cap on their total emissions and our regulation puts a cap on our total emissions, as long as we each met our own regulations, then the total emissions cannot exceed the sum of the two caps.

MR. TABOREK: A. I balked because I think I was about to be arrested for going 48 miles an hour in a 50-mile-an-hour zone. We are obeying the line in both countries and we are about to be charged.

MS. RYAN: A. In fact, setting those laws has a basis, in science, to protect the environment.

MR. TABOREK: A. Yes, you are playing your own law out to us.

Q. I have to admit that I didn't follow your analogy, but that's all right. It sounded interesting.

Just take a hypothetical. Let us assume that Michigan has a 200-gigaton limit, for argument sake. I don't care what it is. Let's say it is. And all other things being equal, they would be at 160 at end of the year, and you have got a problem and you buy some generation from them, say, 4 terawatthours. My calculation is that 4 terawatthours is about 35 gigatons. They are still within their limit, but am I wrong that somehow, in that transaction, we have 35

more gigatons of acid gas emissions in the air?

A. You have made the point there will be more and I have made the point that we are both within the law.

Q. I wasn't asking whether you were complying with the law. I am asking whether your purchase causes more emissions than there otherwise would have been.

A. Yes.

Q. Is it true that if both of you are at your limit, and you need to buy, the result is that purchases are not an option for you, because you can't buy from them, they would be at their limit.

A. Michigan is one entity.

MR. BARRIE: A. That's true. I think it is true. In that situation, yes.

MR. SNELSON: A. I am not prepared to buy the assumption that even if the short-term effect is to increase emissions, that that is, in fact, the long-term effect.

Q. Why is that?

A. Because emissions have a price associated with them, which is the cost of additional control. And in the U.S. system, there is considerable freedom to shift emission allowances from one year to

another.

So, if a utility has used up more of its emission allowance this year, because it sold energy to us, that may cause them to change their acid gas control program either in that year or in subsequent years, so as to reduce their use of emissions allowances.

So, for instance, they may burn more natural gas in some units somewhere, instead of burning coal, or they may add scrubbers to a generating plant, and that may very well lead to the long-term effect being no increase in emissions.

Q. In fact, under the U.S. Clean Air Act, isn't it true that there is a system of tradeable emission credits?

A. Yes.

Q. And they can, in fact, if they are at their limit --

A. That is what I am referring to.

Q. So, if they are at their limit, they could simply go out, put down a million dollars and they have got 35 gigatons more, and they can sell that to you. And all they are going to do is put it in their price to you; isn't that right?

A. The price of the emission allowances,

and I am not sure that the emission allowances have started trading to the point where a price has been established, but the law permits that. That would be one of the factors that they would build into the price of electricity they send to us.

Q. So, the only impact, then, if I understand it right, the only impact is that they charge you more.

A. No. The impact is that they may charge us more, but the price of an emission allowance, because the total emissions are capped. The total amount that they can emit is a physical limit. Because of that, then they presumably have to somehow or another reduce sulphur dioxide emissions, someway or another, to reduce their use of emission allowances somewhere else.

It may be by the utility who is selling to us, or it may be that they will buy an emission allowance from somebody else who will then reduce his SO(2) to create an equivalent reduction.

Q. Fine. Could you pick up Interrogatory 2.14.68, please. This is supplementary information provided in response to this interrogatory. If I read this correctly -- did you say earlier, Mr. Barrie, that you, in fact, wrote this?

MR. BARRIE: A. I did.

Q. If I read this correctly, the fairest assessment is that if you add your purchases for acid gas controls in 1990, the emissions associated with them, to your actual emissions, the total emissions would be 313 gigagrams?

DR. CONNELL: Excuse me, I haven't found the interrogatory. The number again?

MR. SHEPHERD: Sorry. 2.14.68, Dr. Connell. It should actually be the next one on the pile, but if it isn't, it's one down, or a couple down.

THE CHAIRMAN: The figures you were just reading, was that from the first page?

MR. SHEPHERD: It is from the second page at the bottom. It's very hard to read. This is how we got it, unfortunately.

THE CHAIRMAN: It is just the bottom of the page, though.

MR. SHEPHERD: Right at the bottom of the page, yes. 313 gigagrams.

MR. BARRIE: What those figures at the bottom of the page say, are that our own generation caused 245 gigagrams of emissions. To the best that we can estimate, and I have lots and lots of ifs, ands, and buts prior to that, the best we can estimate is

that the result of those purchases was that the utilities we purchased them from would themselves have emitted 68 gigagrams themselves to supply that 7.7 terawatthours of purchase.

MR. SHEPHERD: Q. And you have concluded, in fact, that that is the fairest way of estimating the impact of the purchases; haven't you said that in here?

MR. BARRIE: A. I think I used the words, that is our best estimate.

Q. Okay. Of course, now you have only included in that the 7.7 terawatthours that you purchased for acid gas control; right?

A. That is correct, yes.

Q. So, you haven't included the total of 13 terawatthours that you actually purchased?

THE CHAIRMAN: I'm sorry, 13 what?

MR. SHEPHERD: On the first page, there is 13 terawatthours of total purchases in 1990. But this calculation only includes the 7.7 terawatthours which is part of that 13, which was specifically for acid gas control.

Q. Isn't that correct?

MR. BARRIE: A. That's correct, yes.

Q. And, Mr. Barrie, I just did some

quick math and it looks to me like if you included the whole 13 terawatthours then you would have a total of about 360 gigagrams of total related acid gas emissions in 1990.

A. That would be the acid gas emissions by our interconnected utilities to supply 13 terawatthours to us.

Q. Yes.

A. If it was of the same ratio, and I imagine it would be, and if I trust your arithmetic, then yes.

THE CHAIRMAN: What was that figure again, Mr. Shepherd?

MR. SHEPHERD: 360 gigagrams.

THE CHAIRMAN: 360.

MR. BARRIE: But, now you are adding in a purchase that has nothing to do with acid gas. The additional purchase we made was, in the majority, because we were actually short of capacity, regardless of the acid gas restrictions, and some of it, a small part, was just our normal economy transactions.

MR. SHEPHERD: Q. Well, you say it had nothing to do with acid gas, but surely it did actually produce acid gas.

MR. BARRIE: A. It would have produced

acid gas.

What I am saying is we would have needed that amount of power had there been no such thing as an acid gas restriction. We were actually short of power.

Q. You could say the same thing about every time you burn your coal units; can't you? You only turn them on because you need the power, but that doesn't change the fact that they produce acid gas.

A. Right.

But, if you are going to take all such imports into the account, then I must reiterate that most of the years we actually export, so, presumably, we should subtract that from our acid gas.

Q. Okay.

THE CHAIRMAN: I'm sorry, I am confused. Is the 7.7 included in the 13 or is it--

MR. BARRIE: Yes.

THE CHAIRMAN: --in addition to the 13? It's included in the 13.

MR. BARRIE: It's included.

THE CHAIRMAN: Now, I thought you said in the second page, that 7.7 produced 68 ggs.

MR. BARRIE: Gigagrams.

THE CHAIRMAN: And then you said the 13 produced 360. That can't be right.

MR. BARRIE: No. Mr. Shepherd did the arithmetic, the total --

MR. SHEPHERD: The 13 actually produces 115, Mr. Chairman.

THE CHAIRMAN: Pardon?

MR. SHEPHERD: It produces 115, 13 produces 115.

THE CHAIRMAN: Where did I get 360 from?

MR. SHEPHERD: Well then, 115 plus 245, which is what Hydro produced directly, is the 360 total.

THE CHAIRMAN: Okay.

...

[3:16 p.m.] MR. SHEPHERD: Q. And your acid gas limit in 1990 was 280, wasn't it?

MR. BARRIE: A. Yes.

Q. So that if you had had to include these purchases in yours, in your total, you would have been almost 30 per cent over your limit, is that right, roughly?

MS. RYAN: A. I think the answer is that we don't have to include it in ours. We have a law which specifically limits our emissions, and we have agreements which allow us to purchase, and as Mr. Barrie indicated, purchasing to meet our acid gas regulation was the last thing we wanted to do.

Obviously, from an environmental perspective, we would have preferred to meet Ontario load with Ontario energy. That is what we planned to do in the long run, and we couldn't. But to now change the rules and say they should be added in, I don't think is appropriate.

Q. I take it you will agree that this Board could conclude that it would be a better idea if we didn't export our acid gas problem to the United States and still have the problem. This Board could think about that a little bit.

MR. SNELSON: A. I think you have to

have a consistent set of regulations. And I am not sure that we are in a position at the moment to advise the Board.

But, just a point that should be borne in mind is that if we are going to count all of the acid gas that is produced in Ontario and that the Americans count all of the acid gas that is produced in the United States, that is one system where all the acid gas produced gets counted once.

The other system, where all the acid gas gets counted once is where you try to attribute whose using the electricity and say, "Let's count all the acid gas that is produced by the electricity used in Ontario, no matter where it may be produced."

Q. That is correct.

A. That would require that we count in our limit the acid gas for electricity that is produced outside of Ontario for use in Ontario, but to avoid double counting, and to be fair and equitable, it would also require that the electricity that is produced in Ontario and is used in the United States, be counted as part of the United States' emissions and be credited against Ontario Hydro's emissions.

Q. That sounds very sensible.

A. You have to do both. If you are

going to do one, you have to do both. And attributing the acid gas to where the electricity is used, rather than where it is produced, is a much more complicated system to handle, and it is not the way the current regulations have been framed.

Q. I guess, it is right that your total would be the same in either case. It is just a question of allocating it to various jurisdictions, isn't that right, in your hypothesis?

A. The total would be the same, as long as you counted everything and didn't double count anything. Everything gets counted once. Then clearly the total is going to be the same.

DR. CONNELL: May I ask, is there somewhere in our exhibits any description of the system of tradeable permits that you cited in the United States?

MS. RYAN: It will be in the 1990 State of the Environment Report that should be available by the end of this month, but I don't recall anything in any of the interrogatories we have answered.

Actually, there was one supplementary document for Interrogatory 2.14.61, which was entitled "The Impact on Ontario Hydro of Emissions Traded for Nitrogen Oxides, A Preliminary Analysis." So if you

had that, it would give a background.

DR. CONNELL: That is just for NOx?

MS. RYAN: That is just for NOx. It is a specific study.

DR. CONNELL: There is also a system for total acid?

MS. RYAN: Yes, in Ontario and Canada, we don't have it. In the U.S. Clean Air Act, they have in fact set up a system for trading for SO(2).

DR. CONNELL: And is it regional or nationwide in the United States, do you know?

MS. RYAN: It is nationwide.

DR. CONNELL: Yes. And do I understand that the purpose of it, at least one of the purposes of it would be to ensure that the savings in acid gas or SO(2), which were most easily achievable, would be accomplished first through the trading permits.

MS. RYAN: Easily achievable and cost effective. It is based on the fact that different control technologies have different marginal costs, and so, you should do the cheapest ones first.

DR. CONNELL: Thank you.

MR. SHEPHERD: Q. Now, Mr. Taborek, you said the other day, and I don't have the reference, but I will find it if you ask me to. That 100 gigagrams of

acid gases, I think you actually said SO_2, wasn't very much. Was that you that said that?

MR. TABOREK: A. That is correct. I said it did not have a significant effect on the environment.

THE CHAIRMAN: I am sorry, sir, I'm afraid I didn't hear you.

MR. SHEPHERD: I'm sorry. I am mumbling again. I apologize.

Q. You said that 100 gigagrams of SO_2, I believe was what you said, did not have a significant effect on the environment, is that correct?

MR. TABOREK: A. Yes.

Q. That is not quite half of -- well, I guess it is a little over a third of your total annual limit, and it still doesn't have a significant effect on the environment.

A. Yes.

Q. Let me go back to the 360-gigagram number for a second, because that is what I have calculated all of this on.

Is it fair to say that the volume of acid gas that is represented by 360 gigagrams is approximately the area of the City of Toronto to the height of a person?

A. I do not know.

Q. Does that sound the right range, or do you know?

A. I have no idea. I'm not sure it is relevant.

Q. Well, I'm just following up your testimony that 100 gigagrams is not significant.

A. That is correct. I gave two reasons why I felt it was so.

We also had provision in our regulation for a period to trade amounts of that order from one year to the other, to avoid getting into the kind of problem that we did experience in 1990.

Q. Presumably because 100 is so insignificant?

A. Because 100 is insignificant, yes.

Q. Well, if my example of the volume of that much gas is correct, let's just assume that it is for now, would you say that is an insignificant amount of sulfur dioxide, pure sulfur dioxide?

A. Pure sulfur dioxide? I just think it is totally irrelevant.

MS. RYAN: A. Then when it is emitted...

THE CHAIRMAN: I take it, you mean that it is significant, or not significant?

MR. TABOREK: I just don't see what relevance there is here. If it is 100,000 tonnes, it is not significant. And how you package 100,000 tonnes is irrelevant. It is 100,000 tonnes, and it is not significant.

THE CHAIRMAN: Perhaps you could explain why you say 100,000 tonnes is not significant.

MR. TABOREK: I did yesterday, in a response to...

THE CHAIRMAN: I may have forgotten.

MR. TABOREK: I am sorry, sir.

There are two essential reasons. First of all, officials of the Ministry of the Environment, in attempting to detect the depositions that occur from various sources at, I believe, two instances, took measurements of acid gas depositions around Inco before and after a strike. Inco emits something, roughly three-quarters of a million tonnes at the time, so many -- much more than 100,000 tonnes.

And the reason they actually did it twice was because the first time that they tried to detect it, they could find no difference. The second time they did it, they could get barely detectible differences in depositions very close to Inco for changes...

MS. PATTERSON: When was this?

MR. TABOREK: This was during the early '80s.

MS. PATTERSON: Before or after the high stack?

MR. TABOREK: It was after the high stack.

And so, quantities of that magnitude cannot be detected.

Now the second...

THE CHAIRMAN: At what position? When can't they be detected? At what point can't they be?

MR. TABOREK: They had a number of detectors around Inco, in a wide pattern around the Inco stack. They went to detect. They went anticipating detecting. They were in the high probability places for detection.

And then the second reason is that, in the course of the evolution of our regulations, we had it one time, it was a form of trading, but it was a form of trading with ourselves from year to year called banking. And there was a provision for trading 100,000 tonnes.

Now, in getting that into the regulation, we discussed with the Ministry of Environment officials

as to whether that was environmentally acceptable. And in our discussions with them, we learned that that, in their view, was acceptable, or it was not a significant impact. And they further testified on that basis before legislative subcommittess. And now that I think of it, there is actually a third reason.

THE CHAIRMAN: Just before you leave the second, is that regulation still in place?

MR. TABOREK: No, it was removed.

THE CHAIRMAN: Why was it removed?

MR. TABOREK: The legislature felt it was an escape valve. They liked a neat, closed regulation.

MS. RYAN: Mr. Shepherd...

THE CHAIRMAN: Just one moment.

MS. RYAN: I am sorry.

THE CHAIRMAN: You were going to say a third thing.

MR. TABOREK: That is the essential of the physics and the logic of it, sir. That the nature of the acid rain phenomena is that it is a deposition that occurs and accumulates over a period of years, and the small amounts in one year by virtue of that are not significant, similarly.

And you are looking at, now you have to take depositions and emissions together, but you are

looking at something like total emissions of 20-million tonnes in North America, something of that order, so you are looking perturbations of 100,000 and 20-million, and you need multi years of that to accumulate to cause a problem.

The obverse of the argument is that, if 100,000 tonnes made a big difference, the fact that we have reduced by several hundred thousand tonnes by now would have made marvelous improvements. And the improvements that we will expect are similar gradual improvements over a period of years.

MS. RYAN: Mr. Shepherd, if I could just add one comment to significance of sulfur dioxide. The reason it is difficult to envisage a blob of sulfur dioxide and comment on significance is that the emission, the time over which it is emitted and the concentration at which it impinges whatever we are talking about has a great significance on whether it is considered significant. I don't think you can think of it as one mass emission, because that is not how it happens. It happens from a number of stacks over a length of time.

There is an interrogatory, 2.7.73, which, in fact, comments on some analyses done for our flue gas desulfurization program as part of the

environmental assessment, and looks at total SO(2) deposition in some of the more sensitive areas in Ontario and analyzes how much it due to Ontario Hydro, how much is due to other Canadian and other -- and U.S. sources, and gives some impact for how much is being deposited in each area.

And the analysis indicated that for the Muskokas, the Ontario Hydro impact is quite small in percentage. It would be about four or five per cent.

MR. SNELSON: So, if you completely eliminated Ontario Hydro's emissions, the improvement in the Muskokas would be in the order of four or five per cent.

MR. SHEPHERD: Q. The improvement in Toronto would be higher, but...

MR. SNELSON: A. Pardon?

Q. The improvement in Toronto would be higher, presumably.

MS. RYAN: A. Not likely.

Q. I get the sense, from what you are saying, that you are saying you are spending all this money on acid gas, but it really is not very important. I assume that is not what you are saying.

MR. TABOREK: A. No, that is not what we are saying. We have spent, I think, up till now about

$900-million, and we believe that we have and we will spend, I believe, by the end of the year 2000, something close to $3-billion, and we believe with that we will achieve marked effects in our own emissions, and we believe by taking the leadership role, we have assisted the federal and the provincial government's in negotiating a package with the U.S. government.

...

[3:30 p.m.] So, we believe it is extremely important.

But, having said that, we have always said that the money should be spent where it is effective, and it should not be spent in areas that are not effective, and that it should be spent where there are problems and not where there are non-problems. And that is very easy to do.

Q. Just looking at the chart that you had up in your direct evidence, it looked to me like your acid gas control program was one of your big successes, something that you are quite proud of, that you dropped them substantially. Is that a fair characterization?

A. We have met our objectives I think.

MR. SHEPHERD: Mr. Chairman, do you wish to take an afternoon break now?

THE CHAIRMAN: We will take it now.

MR. SHEPHERD: Mr. Chairman, could you tell me whether this is a four-thirty or five o'clock day?

THE CHAIRMAN: Well, it could be a five o'clock today, if you would like it to be.

MR. SHEPHERD: It doesn't matter to me.

THE CHAIRMAN: Well, we will make it a five o'clock day.

---Recess at 3:32 p.m.

---On resuming at 3:53 p.m.

THE CHAIRMAN: Go ahead, Mr. Shepherd.

MR. SHEPHERD: Q. I would like to follow up some discussion you had with my colleague, Mr. Watson, the other day.

As I understand it, in the same way as with purchases from other utilities, when a non-utility generator produces acid gases, you don't include that in your totals?

MR. BARRIE: A. That's correct.

Q. During the course of Mr. Watson's cross-examination, there was a whole discussion about what would happen to your acid gas compliance if NUGs were included in your limits. Do you recall that?

A. I don't actually, no.

Q. It was on Monday of this week. I can give you the transcript references if you wish. I realize a lot has gone on since then.

MR. SNELSON: A. If you want to ask us anything specific about it, then perhaps we should see the transcript.

Q. I am not going to refer back to that. I guess I am just trying to follow on from it, the next step if you like.

You anticipate that most of your NUGs are going to be natural gas cogenerators; is that correct?

A. Yes, that is correct.

Q. If a NUG is a natural gas generator, am I correct that the NOx would be less than half of the NOx from the equivalent coal burning facility and the SO_2 would be a very small fraction of what you would have from a coal-burning facility; isn't that correct?

A. The SO_2 would be a very small part and negligible. The amount of NOx would depend on the design of the cogenerator's particular facility.

Q. In a typical situation?

A. I believe we have given you some typical numbers and I can't recall what they were, but they would vary from situation to situation.

Q. They are still not close to coal.

A. I doubt that they would be close to coal if they installed combustion turbines of good modern design.

Q. Am I also correct that some of the small amount of acid gas produced by a cogenerator, you would normally expect that to be allocated to the heat load as opposed to the electricity load?

A. You can go through an exercise of

allocating fuel to heat and to electricity production and presumably you can go through a comparable exercise with emissions.

Q. And, in fact, isn't it true that often a NUG cogenerator will displace an existing heat source; for example, a boiler or an oil boiler or a diesel or even a gas boiler of some sort, and that typically that will be less efficient and have a higher acid gas emission than the NUG; isn't that true?

A. I couldn't comment on the relative emissions of the old source versus the new source.

Q. Whatever the relative emissions are, presumably some portion of the NUGs' emissions are not marginal; they are not incremental to what would have been the case just to supply the heat?

A. Presumably, if it is a case where it is an existing heat load and the cogenerator is replacing an existing boiler, then there is the question about how much would the existing boiler have emitted and relative to the new situation. And as I said, I can't comment on the relative magnitude of those.

Q. If increasing NUGs had the effect of decreasing your own coal-fired generation - and just accept that hypothetical, I know it is not necessarily

the case, but let's just accept it for now - as I understand it from these discussions then, the overall SO(2) and the overall NOx would go down, if you displaced one for one megawatts?

A. That is our assumption and I believe it is generally accurate.

Q. In fact, am I right in saying that, if you just theorize for a moment, you could, say, replace all of your fossil generation with NUGs, that your total acid gas emissions would be well under 10 per cent of your current acid gas emissions?

A. I haven't done the calculation and it is a very hypothetical situation. You have to say to yourself, "Is there enough cogeneration available for that to happen? Is there enough gas supply to Ontario for that to happen?" So, it seems to me it is an unrealistic situation.

Q. So, you don't even want to accept it as a hypothetical?

A. In the real world, I don't believe that this situation will occur. I mean, if you want us to speculate on unreal situations, we can do that but I don't know how that is useful.

Q. I would, in fact, like you to speculate regardless of whether you think it is

realistic. But I take it that you can't tell me, even if you do deal with that hypothetical, you can't tell me what percentage your acid gas would be of the displaced coal? You have no idea what the range is, whether it is 10 per cent or 20 per cent or 5 per cent. You just have no idea?

A. The calculation we are speculating here is you eliminate the sulphur dioxide and you may -- you know, it is quite possible that you will be able to reduce the NOx somewhat. So, that gives some range on the numbers but, as I say, it is quite a hypothetical situation.

Q. And it would be a small percentage; is that right?

MS. RYAN: A. Yes.

Q. Okay. Let's not try to nail it to the wall.

Now, these figures we are throwing around, those assume, I guess, that NUGs are not themselves subject to controls under acid gas emissions, don't they? When we are talking about a gas cogenerator having less acid gas emissions, that's today, right, and that's without controls, without any legislated or regulated controls?

A. On NUGs themselves.

Q. Yes.

A. But NUGs, in fact, will meet the existing environmental regulations, even though there are still regulations that NUGs generators have to meet, even though they don't have a cap themselves, yes.

Q. And are you aware of any proposed regulations that would require NUGs to have lower acid gas emissions?

A. I am aware of the draft Clean Air Program which, in fact, covers all industry, and NUGs would be part of that, and it governs sulphur dioxide and nitric oxide emissions, yes.

Q. Are the restrictions, is that a tighter regulation allowing NUGs less SO(2) and NOx than before.

A. Yes. Depending on current emission rates and importance, it could in fact be a tighter regulation for NUGs.

Q. Let me turn to the role of the environment division. I take it that your division's role is still evolving; that is, your place is still evolving within your organization?

A. That's correct. We have been in place about two years now.

Q. Now, your division is only indirectly responsible for Ontario Hydro's environmental compliance; isn't that right?

A. That's correct. As I pointed out in my direct evidence, environmental management is the responsibility of each line manager.

Q. Do you have any supervisory role over the other divisions or the other branches in their environmental compliance?

A. In the sense of supervisory, no.

Q. Your role is more as communicators or facilitators?

A. We have a number of roles: One would be to provide a focus for the environment for Ontario Hydro; another would be to provide assistance to line managers in helping them incorporate environmental considerations into their decision-making; another would be helping Ontario Hydro ensure that appropriate environmental policy and procedures are in place; acting as spokespersons on the environment for Ontario Hydro; generally making sure things don't fall between the cracks.

Even though we don't have direct line responsibility for doing a lot of the work, there may be things which, because it is not clearly one area's

responsibilities may need a special push to make sure that it goes ahead. So, it's generally providing focus for the environment for Ontario Hydro.

Q. In the context of environmental compliance, if in the view of the environment division a particular division or branch or station or whatever was not doing it and it was below an acceptable standard on some environmental issue, am I right that you can really only either talk to them and persuade them to get onside or report to senior management that they are off-side. That's really all you can do.

A. Again compliance reporting is the responsibility of line management, and it's fairly clear if there are areas in non-compliance. But yes, ours would be recommendatory type of input.

Q. Another thing that is puzzling me is the relationship between the environment division and the various environmental committees that Hydro has. You have three environmental committees, as I understand, and I am going to refer you in this context to Interrogatories 2.14.43, 2.14.45, and 2.14.47. They should be together in the package that I handed out.

A. Yes.

Q. And I guess this material explains the committees, so I am not sure that I need you to

explain them again unless you want to give us a brief summary of their role.

A. As I pointed out, since environmental management is the responsibility of each line manager, and Ontario Hydro is a large organization, there is co-ordination required of policy issues and technical environmental issues.

And so the environmental technical committee was established as a director level committee to address technical issues as outlined in the response to the interrogatory.

The environmental policy committee is a vice-presidential level committee to deal with policy decisions in development that cross branches of the corporation.

And the environment division provides support to these committees to make sure they are addressing the appropriate things and help get material together for the meetings and draw their attention to things.

The environmental advisory panel is largely an external committee made up of environmental experts to provide another source of advice to senior management on environmental issues.

Q. Now, when I look at these three

committees, obviously the environment division doesn't control these committees, right, these are not under your auspices, you provide them with assistance?

A. That's correct.

Q. When I look at these three committees, it looks to me like the committee with the most direct influence over Hydro's environmental policies and procedures is the environmental policy committee, the committee of vice presidents.

A. That is correct.

Q. I am just looking at Interrogatory 2.14.45. And on the page headed up "Environment Policy Committee," it says right under that "Level 2 Recommendatory." Can you tell me what that means?

...

[4:07 p.m.] A. Yes, Level 2 is one level below president. It goes down levels in the organization. So, Level 2 is the vice-presidential level, and recommendatory is that they recommend policy decisions to the president for approval.

Q. Okay. I note that the director of the environment division is the secretary to that committee.

A. That's correct.

Q. I am used to public sector committees where the secretary is sort of a non-participant, doesn't have any voting rights, is expected to just sit there and listen. Is that the case here or is this a full membership on the board, on this committee?

A. I can't tell you about voting rights, but the approvals would be by the vice-presidents who make up the committee.

Q. In terms of settling environmental policies or procedures, how are the responsibilities within -- and I say that in the sense of recommending them, because obviously the Board ultimately decides all these things; right? But, in terms of getting to a point where you have something that is going to be decided upon, can you describe the division of responsibilities between these committees, particularly

the environmental policy committee and the environment division, who does what and at what level?

A. It would vary depending on the issue or matter which was having policy developed.

Sometimes the environment division would provide a support role to the specific line organization which has responsibility for that area of the environment; in fact, would do most of the work of developing policy or putting forward a position.

For example, PCB reference plan is the responsibility of the specific branch within the organization and so that group does all of the work and puts the information forward, but the environment division provides a support role to help them.

In other areas, if it weren't clear that one area of the organization were doing it, we might take the lead role and pull the package together for approval.

Q. I guess I am trying to get at the notion of initiatives, if you will. I can picture a committee of vice-presidents sitting around and saying, "Well, shouldn't we be doing something about CO(2)?" I am not sure that I understand correctly that that's how things, initiatives in certain areas, happen at Hydro.

A. Okay. I think what you are talking

about is issue management, issue identification, and $CO_{(2)}$ is becoming an issue that we should address and how are we going to do it. That is really the role of the environmental technical committee which is a director level committee and has the responsibility to identify, in any given year, a list of environmental priorities, that either exist for the organization or will exist, and ensure that a priority is assigned, and that, in fact, there is a specific part of the organization, whether it's a division, a department or environment division, to take lead role in making sure the appropriate program required is in place to address it.

Q. Okay. My question was going to be, is there any sense in which the environment division is sometimes out of the loop in environmental policy issues, but I take it from your answer that you're right in there as part of the loop, if you like.

A. That's correct. The director of the environment division chairs the environmental technical committee and then is secretary of the environmental policy committee and we are involved in that.

Q. Is it fair to say that there isn't really any significant environmental policy development going on at Hydro that the environment division isn't

actively involved in?

A. Not to my knowledge.

Q. In dealing with the environmental policy committee, does the environment division sometimes take pro-active positions attempting to get a policy approved?

A. Yes, that is part of our role.

Q. I am not trying to trick you, I am just sort of trying to get a sense. Is that generally successful? Does the environmental policy committee generally going along with the environment division?

A. It varies. Obviously we don't work alone, we work with our colleagues in parts of the organization where they have a stake in the issue at hand. And certainly by the time that it would go to the policy committee, there would be general consensus that it was a good thing to do.

Q. It sounds, in fact, like a lot of your division's role is sort of an informal consensus building within the organization; is that fair?

A. To improve environmental performance within Ontario Hydro, that is a large part of the job.

Q. Now, you have testified with some pride about the - well, I shouldn't characterize it as that; it sounded proud to me - to the introduction of

an environmental sign-off on board memos.

As I understood your testimony, correct me if I am wrong, under this recently introduced policy, certain board memos have to be reviewed with environment division which can then object to them and even produce a minority report.

You called it environmental sign-off of all board memoranda for projects which have environmental implications. And you went on to say, this makes sure that the appropriate environmental criteria or considerations have been included before it goes up to the board for signature.

In that regard, that's right? Is that correct, that that's essentially what you said to us?

A. Could you just read the last part?

Q. This a quote from page 2747 of the transcript, it says:

"...this makes sure that the appropriate environmental criteria or considerations have been included before it goes up to the Board for signature."

A. It would be to the Board for approval, but generally, yes, that's what I said.

Q. I would like you to turn up 2.14.52. I looked through this, and certainly this not referred

to as environmental sign-off, and correct me if I am wrong, but I don't remember see anywhere where it says the environment division has some sort of special position or preferred position.

A. That's correct, because it's not just an environmental sign-off; there are specific sign-offs for other parts of the organization, like corporate relations, law division, finance, and they were all implemented at the same time.

Q. It looks to me like it's a policy to ensure that five specified components of the organization sometimes see board memos before they are presented to the board; is that right?

A. That's correct.

Q. And there isn't, in fact, even a requirement that the branch submitting the board memo actually go to you at all, is there?

A. That's correct. Since environmental management is a line management responsibility, the vice-president going for board approval makes the decision on whether or not they will go to these various groups for signature. Having said that, the president and the board are quite interested and have specifically asked as to whether input has been obtained.

Q. If, for example, the production branch did a board memo on how to respond to the nuclear moratorium, they could make a determination that that was not an environmental issue and you wouldn't even know about it; is that correct?

A. What was your example again?

Q. The production branch drafted, prepared a memo to the board on how to respond to the nuclear moratorium, what actions to take.

A. First of all, the production branch would not do that, and secondly, the board memos which have a sign-off procedure, as you pointed out, by up to five various signatures, are ones which are financial undertakings.

Q. So, it's not all board memos?

A. No, I didn't say all board memos. Or if I didn't say it, I meant to say appropriate board memos that have environmental implications.

THE CHAIRMAN: I guess what I would like to know is who decides and how is it decided what board memos have environmental implications?

MS. RYAN: The vice-president in charge of the area which is sending the board memorandum for approval is the person who decides.

However, if his or her decision is not

correct, the president or board would request a review by the appropriate people, if they didn't feel the appropriate inputs had been provided, and that, in fact, has happened.

MR. SHEPHERD: Q. Now, in addition to the five people who are on the list for sign-off, and this is the voluntary sign-off, board memos also have to go to the executive committee; do they not?

MS. RYAN: A. I beg your pardon?

Q. Don't Board memos also go to an executive committee?

A. They go to the executive committee before they go to the board.

Q. The executive committee includes the vice-presidents of the major branches; is that right?

A. That's correct.

MR. SNELSON: A. It includes some of the vice-presidents, not all of the vice-presidents.

Q. So, in addition to these five, they also get to see it before it goes to the board?

MS. RYAN: A. That's correct.

Q. And unlike you, they have to see it because they are on the executive committee. It can't go to the board without going through them.

MR. SNELSON: A. A board memo has to go

to the executive committee before it goes to the board. I think there may be very, very rare exceptions but that's 99.95 per cent of the cases.

Q. Close enough.

A. Close enough.

Q. Isn't it, in fact, if you look at the last page of this interrogatory, isn't it, in fact, true that even Mr. Franklin says, this whole process, that is the sign-off, what you refer to as the environmental sign-off --

MS. RYAN: A. I referred to it as the environmental sign-off from our perspective for what we have to do. I am in environment division, we worry about the environmental. I didn't mean to preclude that were other sign-offs as well.

Q. And Mr. Franklin, in fact, says that will apply, and this is not just for environment division but for all of the possible sign-offs from anybody, that he thinks it will apply to only a very small number of board memos each month, doesn't he? Doesn't he, in fact, say in that letter he thinks it will only apply to two or three board memos a month? Is that true?

A. That's what he says.

Q. So, if I got the impression from your

earlier evidence that you were saying the environment division had some sort of special authority to look at all board memos, I got the wrong impression, didn't I?

Because it's not all board memos, and it is not only the environment division. So, it's not a special authority at all.

A. It's an authority which we share with others, that doesn't mean it's not special. And if I said all board memos, I didn't mean all board memos. I meant those with environmental implications, and that's certainly what I meant to say.

Q. Well, sorry. Am I right in understanding it's those with environmental implications, that other branches have decided they want to let you see, that also include a financial commitment; is that right? Isn't that what you just said?

...

[4:22 p.m.] A. That is correct, with the further qualification that should a specific vice-president decide that the appropriate people did not have to see it, and went forward without the sign-off authorities, there is a further check by the president and the board asking for that review.

Q. So, that is really the safety valve, isn't it? The executive committee or the president or the board themselves could say, "This should have gone to the environment division."

A. That is correct.

Q. So, as long as they are acting responsibly that way or understand the issues, you don't have a problem with it slipping by you; is that true?

A. Yes.

Q. Thanks.

MR. TABOREK: A. There is also the vice-president responsible for the environmental division, who is on senior committees that is also in that picture.

Q. And who is that?

MS. RYAN: A. We report to the vice-president of planning, and so I guess I wasn't giving him appropriate credit for ensuring that board

memos...

Q. Is this the vice-president of corporate planning?

A. Pardon?

Q. Is this the vice-president of corporate planning?

A. Yes, our vice-president is corporate planning.

MR. SNELSON: A. And he is a member of the executive committee.

MS. RYAN: A. Executive committee.

Q. He's actually not even...

MR. SNELSON: A. He's one of the vice-presidents.

Q. He's not even your vice-president anymore, is he? I thought he was president.

MS. RYAN: A. But we have a vice-president.

MR. SNELSON: A. We have an acting vice-president.

Q. You have a new vice president?

A. We have an acting vice president.

Q. Who is that, can you tell me?

A. Mr. Kupcis.

Q. Let me turn to another area.

THE CHAIRMAN: Just one moment. I am sorry to interrupt, but in Mr. Franklin's letter of May the 23rd, one of the people who have to sign every draft board memo is the director of the environment, is that not right? That is what it says in the letter. And on the May 23rd, 1989 letter, the first indented paragraph:

"Along the bottom line of every draft memo there will be a line listing with room for initials."

And the last person on that list is the director of the environment.

MS. RYAN: Yes, I think the point that was being made is that whether or not this sign-off sheet goes to environment division and the others on the list is up to the vice-president going for approval.

THE CHAIRMAN: It says every draft board memo.

MR. SHEPHERD: Mr. Chairman, on the previous page, the memorandum from Mr. Leonoff to the vice-presidents, he says:

"It remains your discretions as to what sign-offs you think are necessary."

THE CHAIRMAN: I see.

MR. SHEPHERD: That is where I was going with that.

THE CHAIRMAN: So, that is a direct contradiction to the letter of May the 23rd.

MR. SHEPHERD: That is correct.

I'm ready to go into another area I think.

THE CHAIRMAN: Okay.

MR. SHEPHERD: That area is the area of predicting changes in environmental regulations.

Q. Mr. Taborek, you said earlier, in fact, you said it a couple of times, but I will just quote one time you said it.

"We do not know what environmental rules we'll have to meet in the future. We basically have been hit with a new set of environmental rules roughly every two years during the 1980s. We expect more."

And Ms. Ryan, you said on Monday:

"Part of the mandate --"

Well, actually, that is not true. Mr. Watson said, and you agreed:

"Part of the mandate of Hydro's environmental division is to attempt to

anticipate changes in future environmental regulations and their impact on Hydro's operations."

Do either of those quotes, are they misleading of your views? Are they correct?

MS. RYAN: A. No, it sounds correct.

MR. TABOREK: A. It is correct.

Q. And Ms. Ryan, isn't one of the things that the environment division does each year is prepare a set of corporate assumptions on the environment?

MS. RYAN: A. We coordinate the preparation of that as part of the business planning process. Now, you say each year, for two years, yes.

Q. You have done them for '89 and '90?

A. That is correct.

Q. These are the assumptions that are used in the five-year business planning cycle.

Is it a five-year business plan or a ten-year business planning cycle?

A. Ten-year business planning cycle.

Q. Ten-year business plan. And if you look at Interrogatory 2.14.61, can you just identify that the five pages attached to that here are, in fact, the official environmental assumptions for the business plan for 1989 and '90, or '90 and '91? I don't know

which is -- I can't keep track.

A. For 1990 and '91.

Q. '90 and '91; is that correct?

They are, in fact, dated, so the first three pages are the 1990 assumptions, and then the last two pages are the 1991 assumptions.

A. Yes.

Q. Can you in fact confirm that these are all of the environmental assumptions in the business plan in each of those two years? This is the full set of environmental assumptions in each year?

A. These are the environmental assumptions that are at a level suitable for the business plan and have been included in the business plan. They are not all environmental assumptions that might exist.

Q. Can you describe the purpose of these assumptions?

A. The purpose of the assumptions is that in preparing the business plans, each of the branches will be planning to the same environmental assumptions, and so we will have consistency in the planning process from an environmental perspective.

These are the environmental business planning assumptions. Of course, there are other

business planning assumptions that they would be going on.

Q. And everybody working on the business plan gets the full set of assumptions and is required to follow the same consistent list, right?

A. Yes.

Q. So, the business plan is consistent.

A. That is correct.

MR. SNELSON: A. This is the submitted business plan.

Q. That is right. This is the ten-year business plan.

A. That is right. And why I make the distinction "submitted business plan," business planning assumptions are distributed early in the year, so that all branches can prepare their business plans, which are then combined together into a submitted corporate business plan, and then that is the subject of senior management review. And the approved business plan may very well be different to the submitted business plan.

Q. But, am I right that the point of this assumption system is to make sure that, at least, the process starts consistent?

A. Yes.

MS. RYAN: A. Yes.

Q. When you do that set of assumptions, do I take it correctly, you get a lot of input from other parts of Hydro, you analyze that, perhaps even you get some draft assumptions from people, and you sort of put it all together to a single set of assumptions from all that input?

A. We get input from a number of places and compile it, yes.

Q. And all parts of the organization are required to use these assumptions in the business planning process, except for at the top approval level, where they are not required to do anything; is that correct?

A. These are the assumptions that are to be followed by all branches in preparing their business plans.

Q. So, does that include the people in the organization projecting costs? You have people in the organization projecting future costs; is that right?

A. Again, it would be those parts of the organizations, where it is appropriate that they incorporate environmental -- where the assumptions have some meaning to their area of the business.

Q. Of course, they only have to follow the assumption if it is relevant to what they are doing, right?

A. That is correct.

Q. But if it is, they do have to follow it.

A. Yes.

Q. And, Mr. Snelson, I presume this applies to the assistant planners as well. That you are expected to follow the same set of assumptions in your involvement in the business plan?

MR. SNELSON: A. Yes.

Q. What about the forecasters, the load forecasters? Are they also required to follow those assumptions.

A. I'm not sure which parts of the environmental assumptions would impact on their forecast, and presuming that they had some impact, then it would be a factor they would take into account. But at the time of the business planning assumptions, the load forecast has already been set.

So, by the time the business planning assumptions are produced in February each year, one of the other business planning assumptions is to use the load forecast that was developed the previous December.

Q. Well, that sounds like it is sort of circular, almost for everybody. That is, everybody has to input their assumptions, including the load forecast, but everybody is required to use everybody else's assumptions. It doesn't sound like you could get it in order.

A. When you actually come to the practicality of it, because the load forecast has been set at this particular time, then the load forecast is not going to be changed, at least in the preparation of the submitted business plans request through the business planning process.

So, the environmental assumptions that are used in business planning are unlikely to -- well, there is no way that they can affect the load forecast of that round of business planning, unless it is brought in later, as an adjustment, in the senior management review.

Q. Now, there is, I guess, at any given time when the load forecasters are doing the load forecast, there is a current set of environmental assumptions in effect; is there not?

A. There will be whatever is the set of assumptions and business plans and so on that are in effect at the time that Mr. Burke is preparing his load

forecast.

Q. So, they might be a few months old, but they would still be there?

A. Yes. I'm not sure that I am the right person to be testifying how Mr. Burke takes environmental assumptions into account in his load forecast.

Q. I didn't ask that question.

A. I have no detail on that sort of...

Q. Mr. Snelson, I have not asked how they would take them into account. I have asked whether are they required to. Everybody else is. Are the load forecasters required to use these assumptions?

A. The load forecasters are required to produce the best load forecast they can with all the information that is available to them. How they go about doing that is something Mr. Burke can tell you about, and I can't.

Q. Are there any other parts of the organization that in the business planning process are not required to follow these environmental assumptions? I take it you are saying the load forecasters are not required to follow these assumptions.

MR. TABOREK: A. No, that is not...

THE CHAIRMAN: I don't think he went that

far. At least I didn't hear him go that far.

MR. TABOREK: That is not quite right, because the way it works, the load forecast is produced first, then the assumptions are produced, then the business plan is prepared, and then there is another load forecast, and they use the assumptions that have been valid up to that time. It is a cyclical and iterative process. So, they are using environmental assumptions.

They obviously can't use the ones that are going to be produced a month or two after they do their load forecast, but they use the ones just before.

THE CHAIRMAN: Are you saying, Mr. Taborek, that the forecasters then have to use the assumptions that have been in place? Is that what you are saying?

MR. TABOREK: And their knowledge of events in the corporation to adjust those, yes, is my understanding.

THE CHAIRMAN: I'm not sure what you mean by the knowledge of events in the corporation.

MR. TABOREK: Well, if they know that there is a major difference being proposed, then they would be aware of that, or was going to be proposed, then that would be in their thinking.

MR. SHEPHERD: Q. So, I take it then, Mr. Taborek, that for example when Mr. Burke is doing the 1990 load forecast, which comes out in the spring of 1991, or late 1990, I don't know, I have never been able to figure that out, that he would be using then the set of environmental assumptions that we are here dated March 1, 1990, plus any further information he had as to evolution of those assumptions, after the set.

MR. TABOREK: A. That is my understanding, yes.

Q. And is that, Ms. Ryan, -- I understand it to be that there is a rule that you have to follow the same consistent set of assumptions, is that right?

MS. RYAN: A. That is correct.

Q. Is that a rule that the forecasters are required to do that, or is there an exception for them?

MR. SNELSON: A. The load forecasters produce the best in focus they can with all the information that is available to them.

THE CHAIRMAN: That is not responsive to the question, with great respect.

MR. SNELSON: I don't know of any rule

that is written down that says what they have to include in their load forecast and what they do not have to include in their load forecast.

MR. SHEPHERD: Q. Is there a rule that everyone else has to follow the same set of assumptions for the business plans?

MR. SNELSON: A. The business plan is prepared in the manner which we have described.

...

[4:37 p.m.] Q. I said everyone else, Mr. Snelson. The question requires just a yes or a no. There is a rule or there is not a rule.

A. The business planning assumptions are issued in February for all those groups who have to prepare business plans to prepare their submitted business plans. The load forecast is one of the assumptions in that set of business planning assumptions.

The load forecast has not changed as part of the process of going from business planning assumptions to a submitted business plan.

The business planning assumptions only have life during that time period. You then have the question of what is the approved business plan as a result of whatever modifications are made to the submitted business plan. And the approved business plan and any other information available to them would be taken into account in the load forecast.

But the business planning assumptions have one purpose, and that is to allow the organization on as consistent a basis as we can to move from a period in February where we try and get everybody in line with a fixed set of assumptions to prepare a consistent set of submitted business plans.

Q. I am obviously having a hard time making myself clear.

Forget the load forecast, please. We will come back to it later. Just forget it. Just deal with everybody else. There is a set of assumptions prepared?

A. Yes.

Q. What is in them doesn't matter. There is a set?

A. Yes.

Q. Is there a rule that says that everybody who does a business plan after that point in time for their division must follow that set of assumptions?

A. The set of assumptions are --

Q. Excuse me, Mr. Snelson --

A. No.

Q. It is a yes/no question. You can then qualify it afterwards if you wish.

A. The set of assumptions are distributed to the organization --

Q. Excuse me. Mr. Chairman, I am having a hard time getting a straight answer here.

THE CHAIRMAN: I think you could answer the question yes or no and then expand on it if you

wish.

Is there a rule that requires people to adhere to these assumptions?

MR. SNELSON: There is a memo from the president instructing people to follow those instructions. And if that's a rule in your sense, that is a rule. And that's the explanation I was trying to give.

MR. SHEPHERD: Fair enough. Okay.

Q. But because the load forecast - now we are getting back to the load forecast - because the load forecast is part of those assumptions, the load forecasters can't follow them because they are chronologically prior in the process; correct?

MR. SNELSON: A. Yes. In preparing their load forecast, they are chronologically prior to the forecast. They are actually required to follow those assumptions in preparing their own input to their business plan about their own costs and staffing and so on for their own unit.

Q. But not in preparing their load forecast?

A. Not when preparing their load forecast, though it is possible that the load forecast may be changed as part of a subsequent review of the

business plans.

Q. All right. But you have said, Mr. Taborek, that although there is no rule that says they have to follow them, in fact, in practice they will follow the previous set and update them.

MR. TABOREK: A. And with their knowledge. That leads to the point Mr. Snelson made that if by some chance they should end up with an incompatible business plan -- load forecast, I am sure it would be adjusted.

Q. Now, Ms. Ryan, the forecasters, in fact, in Panel 1 testified -- they were asked extensively about how they make their assumptions, especially on environmental issues, and what they said is they make their own assumptions. They didn't refer to your assumptions at all. Did you know that?

MS. RYAN: A. Not explicitly, no.

What sort of environmental assumptions do you mean for them?

Q. I am not sure I understand your question?

MR. SNELSON: A. I don't think we are familiar with the testimony that you are referring to from the load forecast group. Maybe it would help us if we could see what they have said and that would help

in interpreting whether it was consistent or inconsistent with the evidence that we have given you.

Q. There is quite a number of references - that is why I didn't give you the list - because it was talked about for a long time.

A. It is very hard to comment on what they have said without seeing what they have said and in what context.

Q. If we have to pursue that in detail, I will give you the list of references. I think that's fair.

When you do these assumptions you are not just "blue-skying" it, you are not just saying, "Well, I think something might happen in the future, that's my sense, that's my feel." You are using quite hard data to do that, aren't you, to give the assumptions?

MS. RYAN: A. Yes.

Q. Specific knowledge of specific proposals?

A. Our knowledge would be based on draft regulations that are either already on the table or we know are coming, or consultation processes with government and industry to discuss future regulation or future direction, and also seeing what is happening in other jurisdictions.

So, there would be a reasonable probability of the types of things that you see here happening. And actually, in a lot of cases, it is more than a reasonable probability; we know specifically that regulations will be kicking in on specific dates.

Q. So, if you just think, sort of your own knowledge of the trend in a particular area, say CO(2), if you just think that there is going to be tighter regulation, that doesn't go in the assumptions unless you have some specific consultation process or some specific proposals from the government?

A. No, that's not correct.

But the less sure we are of either the timing or the level to which there would be regulation or change required, the less specific the assumption would be.

With respect to CO(2), we would indicate that there was a need to look at potential for CO(2) reductions in the future or there are many aspects to looking at a problem, not just control equipment to do it. There is a lot of front-end work in research and development and design work in feasibility studies that can be done to lead up to it. So, we would try to encompass both types.

Q. I am just trying to make sure I

understand this here. You are constantly talking to governments - federal, provincial, municipal, sometimes, presumably - and other stakeholders, about changes in environmental regulations, isn't that true, Ms. Ryan? It is an important part of what you do in the environment division?

A. Yes.

Q. And you could simply get a sense that there is a direction that is going to happen. I assume that if you just have a sense and nothing more specific, that you are not going to put an assumption in your business planning assumptions.

A. It would depend on the specific sense and area.

Q. On the other side, if there is a specific government proposal on the table for a regulation and in your view after negotiation it will be softened, would you typically put as the assumption the softer version that you expect to come into place?

A. Can you be more specific? I mean my answer to that is "not necessarily."

Q. Let's say there was -- well, you have, in fact, I think said -- let me see if I can find one. I am sure there was one in here. No, it might take me a few minutes to find that. I will leave that

for now.

Now, am I right in assuming that for the purposes of its 10-year business planning, Hydro only looks at, through your assumptions process, only looks at existing regulations and at proposed regulations that have a high likelihood of being enacted, as you would not put in your assumptions either a proposal that you thought wasn't going to make it or something that was not proposed unless you knew it was likely to be, very likely to be?

...

[4:50 p.m.] A. To go into the business planning assumptions to be costed as a business plan, there would have to be a reasonable probability that it would happen. However, we can cover-off the more improbable types of things with research and development and design studies, without having the operating parts of the business, having to physically put money in a budget for control technology. I mean, there are lead-ups to knowing what alternatives might be available should one of the less probable assumptions happen.

MR. SNELSON: A. The corporation may also make allowances in its financial planning for the cost of things which are not yet known about, some of which might be the costs of meeting additional environmental regulation.

So, in the financial planning, they have the capability, if they feel that it is desirable - and this would be subject to direction from senior management - to put into the projections of future costs, unidentified costs to cover -- to allow a contingency to cover unforeseen, things that are presently unforeseen and unidentified, and additional costs due to environmental regulation could be part of that.

Q. Those would be decisions made by the financial analyst, not by people directly related to environmental regulation?

A. It's decisions that would be made at quite a high level in the corporation, and I would expect vice-presidents, if not the president, to be involved in those sorts of decisions. They would be incorporated into the financial projection by an analyst but the analyst wouldn't make the decision.

Q. Is this something that the environmental policy committee might do, is make a suggestion that some sort of contingency be taken for something you don't know about but might happen?

MS. RYAN: A. Not to my knowledge.

Q. Mr. Snelson, is that sort of what you were driving at, that it would have to be at that sort of level that the suggestion was made?

MR. SNELSON: A. It would probably be something that was proposed from within the finance branch or the corporate planning branch and would be approved by the executive committee or the senior management committee with the president present.

So, it would be decided at a very high level in the corporation involving vice-presidents, but it might very well not be the environmental policy

committee where the decision was made. I am saying, the allowances that I am talking about are to cover a wide variety of cost uncertainties that the corporation faces and they are not just necessarily environmental cost uncertainties.

Q. Ms. Ryan, would you agree that proper planning, especially long-term planning, requires not just that you plan to meet current regulations or even proposed regulations, or even ones that you know about, but that you should be taking into account trends and possible future environmental regulation and controls in the planning; would you agree with that?

MS. RYAN: A. For long-term planning, yes, you should take into account future requirements.

Q. And in taking into account the future requirements, would you agree that you should not limit yourself to the things you know about right now, that you should look beyond those?

A. Are you talking from a technology point of view or an environmental concern point of view?

Q. Both.

A. To the extent that you are able to with your present knowledge base, yes.

Q. Does that mean that if, because of

lack of knowledge, you may think there is a trend to tighter regulation in a certain area, but you don't have enough knowledge to really know that that's going to happen, that you should not include that in your planning exercise for long-term planning?

A. I think your planning exercise has to hold in it enough alternatives to cover a number of eventualities.

Q. Sort of a flexibility in the planning?

A. Because the one thing you know, that what you know now, and what you are planning for, will probably not be reality when you get there.

So, I agree that you have to anticipate to the extent that you can and accommodate alternatives to meet the requirements.

Q. Do you believe - do "you" believe - that -- before I get to that.

Mr. Snelson, you are the planner, in fact. Do you agree with the statement I made about planning, that you should take into account not only existing proposed and known future regulations, but also possible future regulations that you don't know about yet?

MR. SNELSON: A. It is important to have

flexibility in plans to accommodate a wide range of possible futures and changes in regulations is one of the potential future changes which we try to retain flexibility in our plans to accommodate.

Q. Ms. Ryan, do you believe that within the next 25 years there will be substantial regulation of CO(2)?

MS. RYAN: A. I am not sure what form it will take, but yes, I think there will be a move to limit or reduce CO(2).

Q. And do you think it will be significant?

A. Can you define "significant"?

Q. Pick your own definition.

MR. TABOREK: A. But don't tell us!

Q. Just tell us what it is. I don't want to get into one of these discussions again about what is significant.

MS. RYAN: A. You can't define significant just by one parameter, because there are so many things that could cause it to be more or less significant when you get there.

Q. Some of the limits that have been talked about, the standing-pat position where we stay at the same as, what is it, 1988, that's one of the

proposals that has been made?

A. I believe it's stability at 90 levels or reduction of 88 levels by the year...

Q. Reduction of 88 levels by 20 per cent, that's one of the other proposals?

A. Yes.

Q. And there have been proposals of carbon taxes or emissions credits to meet that sort of target?

A. There are many thoughts on how to do it.

Q. Which include those examples?

A. Yes.

Q. And would it be fair to say, if anything like those sorts of limits were put in place with the sorts of proposals that have been made to get there, that they would have significant impact on Hydro's activities?

A. I guess it depends on our future generation mix.

MR. SNELSON: A. If you have read Exhibit 40, you will see that we have done an evaluation of some broad-brush thinking about what CO(2) limits might mean for the electricity system, and because of the uncertainties that Ms. Ryan referred to

in her testimony as to the how carbon dioxide regulations would be implemented, if they were implemented, and I believe I heard Mr. Burke testifying to the uncertainties as to how that would affect the load for electricity, if at all, that the broad-brush treatment in Exhibit 40 is appropriate, I believe.

Q. And what is the conclusion of that report, just generally?

A. The report looks at the consequences of various implications of CO(2) and comes to the conclusion that a number of the directions that we are going to in our planning are directionally in the right direction for a situation where carbon dioxide might be limited.

Q. Haven't you said, Mr. Snelson, in the Demand/Supply Plan, that at the present time there is no economic way of reducing CO(2) emissions from fossil generation?

A. We said there is no economic way of removing carbon dioxide from the waste gas stream of fossil fuel generation.

Q. That was stated by you in the Demand/Supply Plan; isn't that right?

A. I believe we have said that. I believe it to be true.

Q. So, the current plan, to the extent that it continues to include fossil, am I right in assuming that it does not take into account the potential for significant CO(2) regulation?

A. The current plan compares our carbon dioxide emissions to a 20 per cent reduction by the year 2005 as an illustrative target as a potential measure of whether or not we are in the direction of reducing carbon dioxide by that amount.

...

[4:58 p.m.] Q. Just one more question on 2.14.61. Only answer it if you have a quick answer, otherwise, you can answer on Monday morning.

In the original answer to 2.14.61, you said, and that is on the first page of this, before the supplementary material, you said:

"Predicting the outcome of such consultations,"

that is, future regulations,

"or specific documentation on the development of regulations is not relevant to the Demand/Supply Plan."

Can you explain what you mean by that?

MS. RYAN: A. I believe, it meant that the options available in the Demand/Supply Plan covered a wide range of alternatives for the future, and that to predict specific numbers, which could be met by that range of alternatives, was not relevant to provide. We did subsequently provide you with the assumptions.

Q. Yes, of course. Would you agree that the testing, whether in various potential futures your plan is flexible enough to cover, say, different types of environmental regulations, is part of what we are doing here?

A. Certainly, this process is looking at

the plan in the broadest sense, and how it will meet the needs of the province, yes.

MR. SHEPHARD: Mr. Chairman, this might be a good time to adjourn for the weekend, if that is convenient.

THE CHAIRMAN: All right. We will adjourn now until Monday morning at 10:00 o'clock.

---Whereupon, the hearing was adjourned at 5:01 p.m., to be resumed Monday, June 3, 1991, at 10:00 a.m.

JAS/KM/RT

[illegible]

[illegible] answer, otherwise,

[illegible]

[illegible] you

said, and that is on the first page of [illegible] before the

[illegible] you said:

[illegible] of such

consultations."

that is, future regulations

"or specific documentation on the

[illegible]

relevant to the Demand/Supply Plan."

Can you explain what you mean by that?

MR. SHAW: A. I believe, it meant that

the options available in the Demand/Supply Plan covered

a wide range of alternatives for the future, and that

to predict specific outcomes, which would be met by that

range of alternatives, was not relevant to provide. We

did subsequently provide you with the assumptions.

Q. Yes, of course. Would you agree that

the testing, whether in various potential futures your

plan is flexible enough to cover, say, different types

of environmental regulations, is part of what we are

doing here?

A. Certainly, that process is looking at